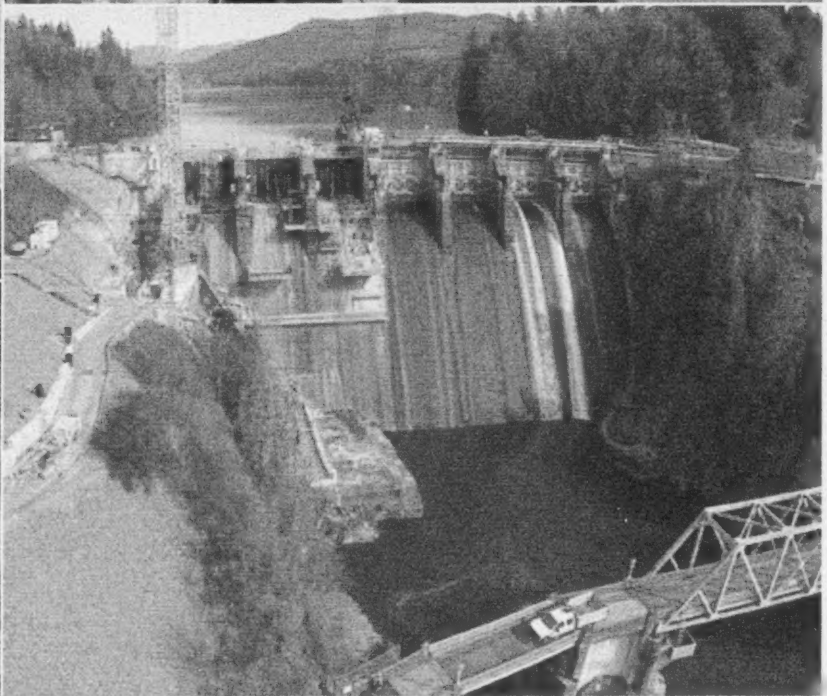
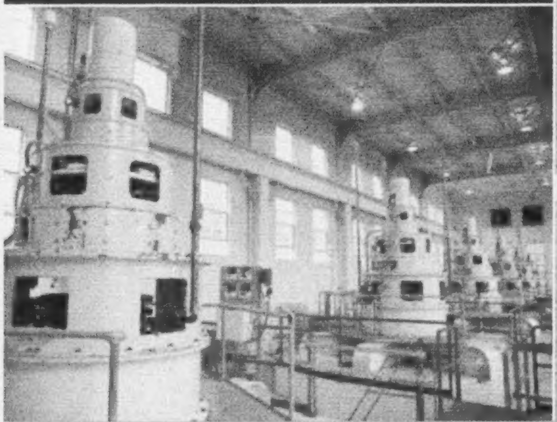




BC HYDRO ANNUAL REPORT 2014

BChydro

FOR GENERATIONS

BRITISH COLUMBIA

TABLE OF CONTENTS

1 Northwest Transmission Line Project

2 Powerline Technician climbing distribution pole

3 John Hart Generating Station

4 Ruskin Dam Safety and Powerhouse Upgrade, photo credit to Birdseye View Aerial Video and Photography

STATEMENT OF ACCOUNTABILITY

On behalf of the Board of Directors, the Executive Team and employees, I am pleased to submit BC Hydro's fiscal 2014 annual report, which was prepared under the Board's direction in accordance with the *Budget Transparency and Accountability Act* and the *BC Reporting Principles*. The Board is accountable for the contents of the report, including what has been included in the report and how it was reported.

The information presented reflects the actual performance of BC Hydro for the 12 months ended March 31, 2014 in relation to the 2013/14-2015/16 Service Plan. The Board is responsible for ensuring internal controls are in place to ensure information is measured and reported accurately and in a timely fashion.

All significant assumptions, policy decisions, events and identified risks, as of June 19, 2014, have been considered in preparing the report. The report contains estimates and interpretive information that represent the best judgment of management. Any changes in mandate direction, goals, strategies, measures or targets made since the 2013/14-2015/16 Service Plan was released and any significant limitations in the reliability of data are identified in the report.

Stephen Bellringer
Chair, Board of Directors

LETTER FROM THE CHAIR TO THE MINISTER

TO: THE HONOURABLE BILL BENNETT, MINISTER OF ENERGY AND MINES AND MINISTER RESPONSIBLE FOR CORE REVIEW

Stephen Bellringer
Chair, BC Hydro

As demand for electricity grows due to population and economic growth our customers look to BC Hydro's clean electricity to power their homes and businesses. This growth comes as BC Hydro's dams and other assets reach an age when they need significant investment in order to continue operating safely and effectively while maintaining B.C.'s clean electricity advantage.

This year, BC Hydro and the Province of B.C. collaborated on a wide range of issues to reduce pressure on rates, gained approval on a long-term plan to meet the power needs of B.C., and efficiently managed BC Hydro's operating costs while continuing to implement our substantial capital plan.

MEETING BC'S ENERGY NEEDS

Meeting current and future demand for electricity is the foundation of BC Hydro's planning activities. B.C.'s economy has continued to expand, bringing new businesses, industry and people to the province. At the same time, new consumer technologies are becoming available, and more of B.C. is becoming electrified.

BC Hydro considers all of these trends as we plan for the future. The Integrated Resource Plan outlines how BC Hydro will meet British Columbia's increasing energy needs over the long term. The plan was approved by the Province in November 2013, and is consistent with the provincial energy objectives formalized in the *Clean Energy Act*, including electricity self-sufficiency, reduced greenhouse gas emissions, support for clean energy and economic development.

Even with all the investment in our system, conservation remains the first and best choice to meet future demand growth. BC Hydro will invest $1.6 billion in conservation over the next ten years. Such measures are less expensive, have lower environmental impact, and benefit customers directly. Through our Power Smart program, BC Hydro is a recognized leader in conservation, providing a range of programs and incentives to help our customers conserve, be more efficient, use power wisely and ultimately use less. In fiscal 2014, the cumulative savings from Power Smart equaled the amount of electricity to meet the annual needs of more than 440,000 homes in British Columbia. Conservation programs keep us on track in our mandate to slow the increase in electricity demand, and that helps keep rates for residents and businesses in B.C. affordable.

As a major investment, smart meters are helping us modernize the electricity system, reduce electricity theft and cut down on wasted electricity. Delivering electricity to customers when and where it is needed, and giving customers new tools to help them save energy and money, will help keep our rates competitive. By the end of fiscal 2014, 99 per cent of new meter installations were complete – a significant milestone for the program – and those customers who had requested alternatives to smart meters were offered options through the Meter Choices Program.

The Site C Clean Energy Project, a proposed third dam and hydroelectric generating station on the Peace River in Northeast B.C., is currently undergoing a cooperative environmental assessment process by federal and provincial regulatory agencies and recently completed the Joint Review Panel stage. In addition, the Crown has a duty to consult and, where appropriate, accommodate Aboriginal groups. The environmental assessment process is expected to be complete in the fall of 2014.

A 10 YEAR PLAN FOR RATES

While making these much-needed investments and balancing the long-term energy requirements of the province, BC Hydro must also keep rates competitive for customers. In November 2013, a 10 year plan was released by the Province. This plan will keep electricity rates as low as possible while BC Hydro makes investments in aging assets and new infrastructure to support British Columbia's growing population and economy.

This Plan builds on the 2011 Government Review. New measures in the 10 year plan will reduce the amount of money that the Province receives from BC Hydro creating additional opportunity to support investments in infrastructure. In early 2014, we completed the 50 recommendations directed to BC Hydro from the 2011 Government Review. Since the Government Review, BC Hydro has reduced its workforce by more than 900 non-operational positions and has found operating cost savings of more than $391 million. BC Hydro will continue to manage operating costs which are forecast to increase at less than the rate of inflation over the fiscal 2015 to fiscal 2017 period.

POWERING THE PROVINCE, SAFELY AND EFFICIENTLY

BC Hydro is working hard to transform our safety culture and we provide the tools our employees, contractors and the public need to go home safely each day.

We have now implemented seven of the recommendations of our Safety Taskforce. While we did not meet our safety performance targets in the areas of All Injury Frequency and Severity, our statistics are showing that we have started to make a positive shift in the frequency of serious injuries and severity significantly improved over fiscal 2013.

The safety and engagement of our employees is fundamental to achieving our goals. In fiscal 2014, 72 per cent of employees completed our Employee Survey, surpassing last year's participation levels. The 2013 employee survey revealed improvement in both response rate and in engagement results increasing to 79 per cent.

In fiscal 2014, we built on our relationship with our customers, First Nations, stakeholders and suppliers. We have provided our customers with new tools to manage their energy use and we continue to implement more efficient procurement practices. We also have gold-level designation for best practices in Aboriginal relations as measured by the Canadian Council for Aboriginal Relations' Progressive Aboriginal Relations program.

BC Hydro continues to focus on running our business in a streamlined and efficient way. BC Hydro's net income in fiscal 2014 was $549 million, $4 million higher than target.

Electricity is essential to our province's economy: it powers our industries and businesses, and keeps our homes comfortable. Our customers count on us to provide safe, reliable electricity – whether they are in a downtown Vancouver condo or a new business in Fort St John, and they want to know we are providing that electricity in a responsible, safe and effective manner. Ensuring we have the right building blocks in place to prepare for these needs is how we continue BC Hydro's legacy for years to come.

Respectfully,

Steve Bellringer

Stephen Bellringer

Chair, Board of Directors

ORGANIZATIONAL OVERVIEW

OUR MANDATE

To generate, manufacture, conserve, supply, acquire, and dispose of power and related products.

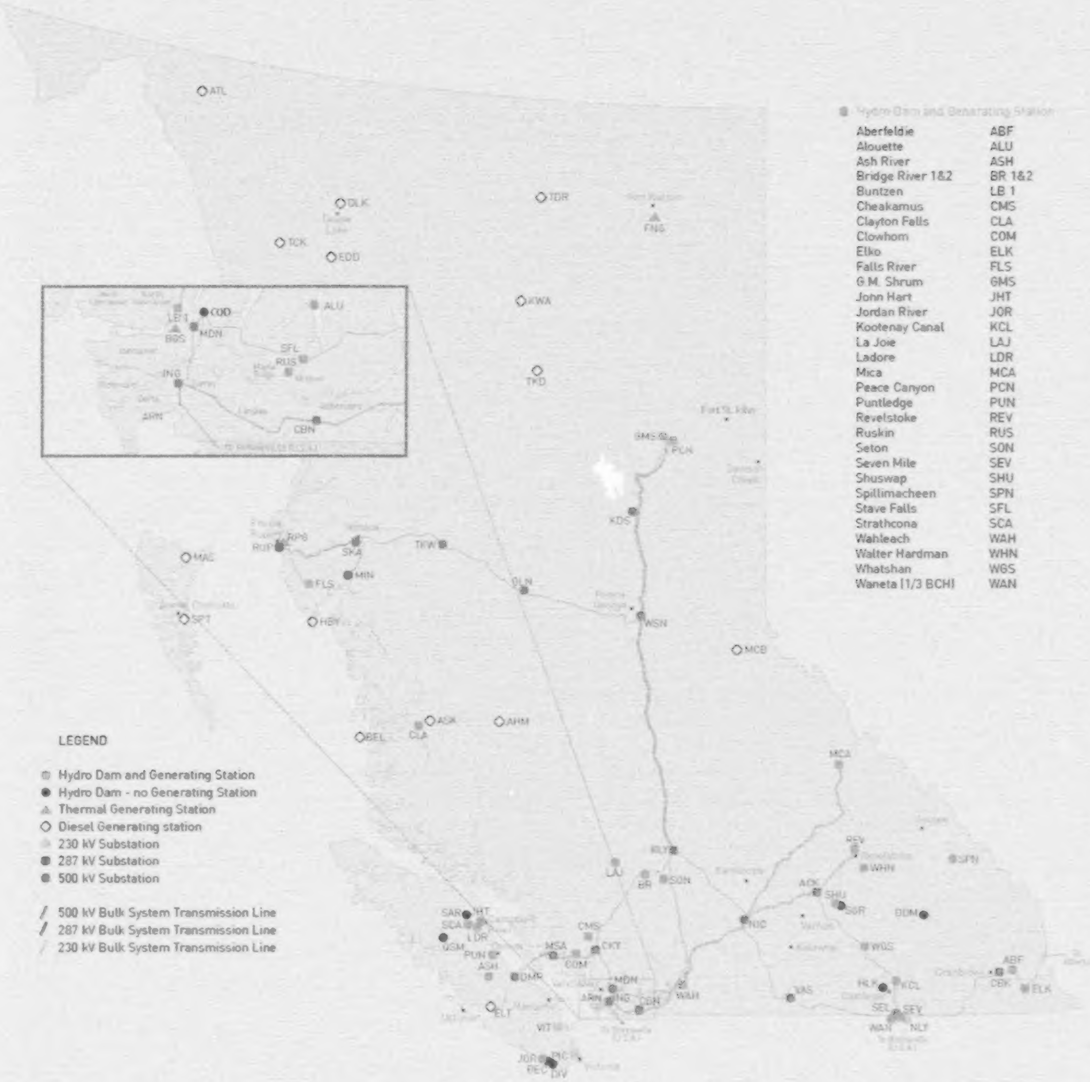
OUR VISION AND VALUES

BC Hydro's vision is: "Powering B.C. with clean, reliable electricity for generations" and there are six core values that are essential to our success: accountability, integrity, safety, service, teamwork and ingenuity.

OUR OBJECTIVES

Our Strategic Objectives guide our actions. Listed below, these are each supported by corresponding strategies, performance measures and targets. Each performance measure has a definition and rationale, as well as benchmarking measures that allow a comparison of performance over time. These measures track our progress on delivering key priorities. BC Hydro management is responsible for measuring performance against targets, and results are reported to the Board on a quarterly basis and publicly in the Annual Report.

OVERVIEW OF BC HYDRO SYSTEM



Hydro Dam and Generating Station	
Aberfeldie	ABF
Alouette	ALU
Ash River	ASH
Bridge River 1&2	BR 1&2
Buntzen	LB 1
Cheakamus	CMS
Clayton Falls	CLA
Clowhom	COM
Elko	ELK
Falls River	FLS
G.M. Shrum	GMS
John Hart	JHT
Jordan River	JOR
Kootenay Canal	KCL
La Joie	LAJ
Ladore	LDR
Mica	MCA
Peace Canyon	PCN
Puntledge	PUN
Revelstoke	REV
Ruskin	RUS
Seton	SON
Seven Mile	SEV
Shuswap	SHU
Spillimacheen	SPN
Stave Falls	SFL
Strathcona	SCA
Wahleach	WAH
Walter Hardman	WHN
Whatshan	WGS
Waneta (1/3 BCH)	WAN

Hydro Dam - no Generating Station	
Bear Creek	BEC
Coquitlam	CQD
Duncan	DDM
Hugh Keenleyside	HLK
Diversion	DIV
Quinsam	QSM
Salmon River	SAR
Sugar	SGR

Thermal Generating Station	
Burrard	BGS
Fort Nelson	FNG
Prince Rupert	RPG

Diesel Generating station	
Ah-Sin-Heek	ASK
Anahim Lake	AHM
Atlin	ATL
Bella Bella	BEL
Dease Lake	DLK
Eddontenajon	EDD
Elhlateese	ELT
Hartley Bay	HBY
Kwadacha	KWA
Masset	MAS
McBride	MCB
Sandspit	SPT
Telegraph Creek	TCK
Toad River	TDR
Tsay Keh Dene	TKD

230 kV Substation	
Arnott	ARN
Nelway	NLY
Pike Lake	PIK
Vancouver Island	VIT

287 kV Substation	
Minette	MIN
Rupert	RUP

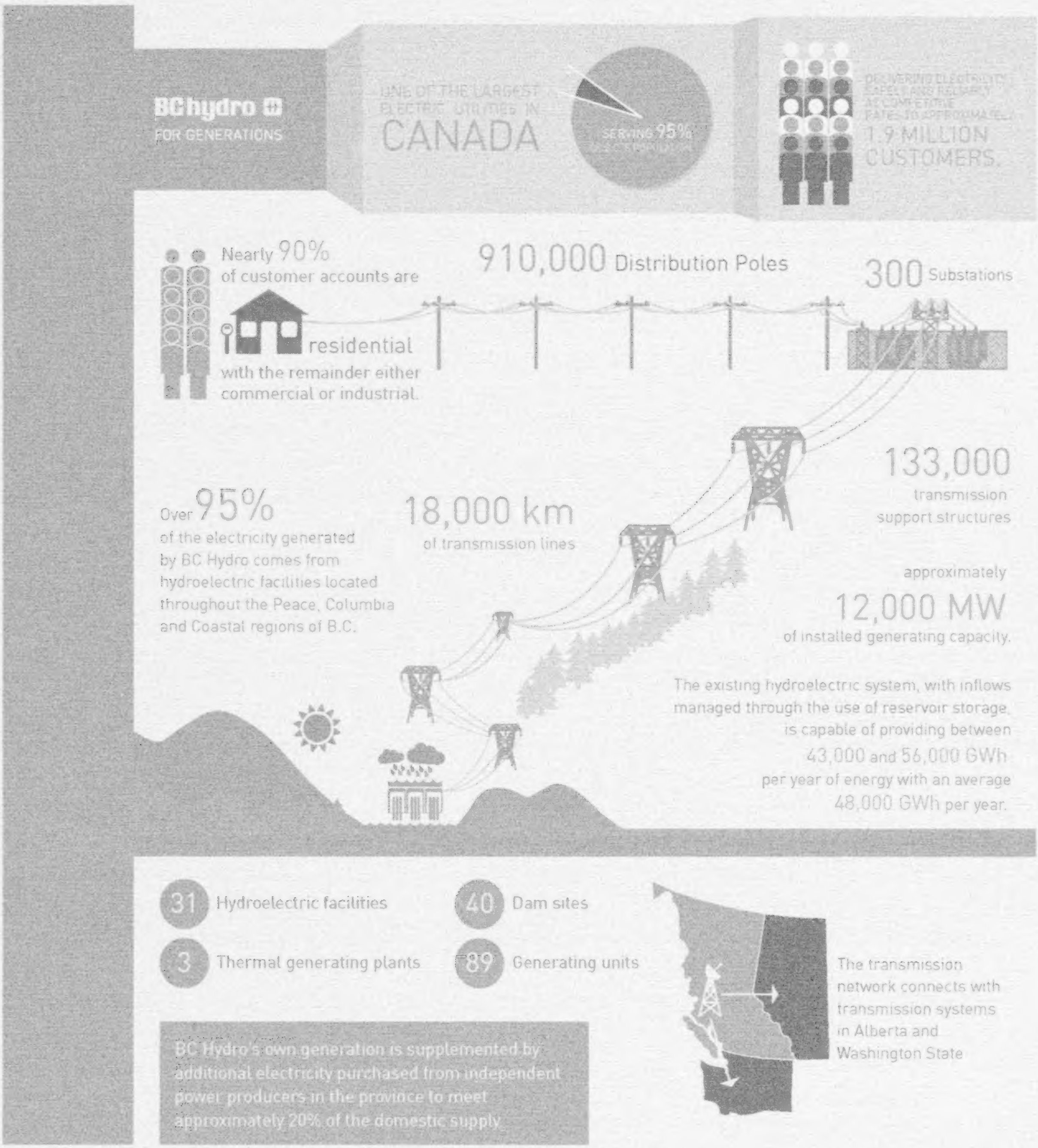
500 kV Substation	
Ashton Creek	ACK
Cheekye	CKY
Clayburn	CBN
Dunsmuir	DMR
Glenannan	GLN
Ingledow	ING
Kelly Lake	KLY
Kennedy	KDS
Malaspina	MSA
Meridian	MDN
Nicola	NIC
Selkirk	SEL
Skeena	SKA
Telkwa	TKW
Vaseux Lake	VAS
Williston	WSN

WHERE WE OPERATE

BC Hydro has offices in more than 100 communities throughout British Columbia and our employees operate in some of the most difficult terrain in the world. Our transmission system connects with transmission systems in Alberta and Washington State, which improves the overall reliability of the system and provides opportunities for trade. Our largest offices are located in the Lower Mainland in Vancouver and Burnaby, with regional offices in Castlegar, Cranbrook, Nanaimo, Prince George, Revelstoke, Vernon, and Surrey.

ABOUT BC HYDRO

BC Hydro was created over 50 years ago to generate and deliver clean, reliable and competitively priced electricity to homes and businesses throughout British Columbia. The electricity generated by our dams and delivered by our transmission and distribution infrastructure has powered B.C.'s economy and quality of life for generations. With prudent reinvestment and careful planning, BC Hydro is positioned to safely deliver clean, reliable power for the long-term benefit of the growing province.



OUR RELATIONSHIPS

BC Hydro works hard to build positive relationships with our customers, stakeholders, First Nations, partners and suppliers. One of our strategic objectives: Succeed Through Relationships provides the opportunity to focus on how we work with First Nations, our customers and other stakeholders.

In fiscal 2014, we continued to focus on diversifying our supply base and enhancing our relationships with the businesses we work with.

OUR SUPPLIERS

BC Hydro's supplier relationships are critical to our success. Through collaboration and dialogue, we continue to work with our suppliers and partners to seek mutual, value-added opportunities in order to obtain materials and/or services on-time, reduce costs and safely optimize performance. In fiscal 2014, BC Hydro worked with a diverse supply base of approximately 8,000 entities to purchase goods and/or services ranging from poles and wires to engineering and construction services.

THE COLUMBIA RIVER TREATY

The Columbia River Treaty is an international water management treaty between Canada and the U.S. BC Hydro, as the Canadian Entity under the Treaty, closely cooperates with its counterpart in the U.S., the U.S. Entity represented by Bonneville Power Administration and the U.S. Army Corps of Engineers. The Canadian Entitlement provided to Canada by the United States varies from year to year. For fiscal 2014 it was approximately 4,425 GWh of firm energy and approximately 1,330 MW of capacity. This entitlement is half of the extra power capability at generation facilities in the U.S. that results from the improved water regulation made available by the Columbia River Treaty. The Canadian Entitlement is owned by the Province of B.C. and is marketed on its behalf by Powerex. The Columbia River Treaty has no expiration date, but either the U.S. or Canada can terminate most of the treaty provisions in 2024, provided written notice is given a minimum of 10 years in advance. The Province of BC is currently leading a provincial review of the future of the Columbia River Treaty and BC Hydro provides technical and other support to the process.

KEY PARTNERSHIPS

Accenture Business Services of British Columbia (Accenture) provides transaction services for customer care, human resources, accounts payable and office services under a seven year outsourcing agreement that came into effect in 2011.

TELUS provides data centre operations and help desk services under a five year outsourcing agreement that came into effect in 2012.

SNC Lavalin Operations & Maintenance Inc. provides facilities management services under a five year outsourcing agreement that came into effect in 2011.

Fujitsu provides information technology application services under a five-year outsourcing agreement that came into effect in 2012.

Independent Power Producers (IPPs) provided 11,025 GWh of energy to our system in fiscal 2014. These 84 contracts provide about 20 per cent of total domestic supply. They will continue to play a significant role in helping us provide reliable, clean and cost-effective electricity supply for many years to come.

Groups of suppliers such as **Line Contractors** or **Vegetation Maintenance Contractors** are integral to BC Hydro's operations. In fiscal 2014, contracts totaling $130 million were awarded to transmission and distribution line contractors across British Columbia, and we continue to build on our relationships with these important organizations to ensure we have the flexibility we need to operate our system efficiently.

CAPITAL PROJECTS

The following two lists highlight the key projects we completed in fiscal 2014 exceeding $50 million, as well as ongoing and planned projects expected to exceed $50 million. The Ongoing and Planned projects are listed by targeted completion date. The following projects have been approved by the Board of Directors. For more information on project details and timelines, visit www.bchydro.com/energy-in-bc.

RECENTLY COMPLETED PROJECTS

SEYMOUR ARM SERIES CAPACITOR STATION	November 2013 In-Service	$48 Total cost ($ millions)
Constructed a 500 kilovolt (kV) series capacitor station adjacent to two existing 500 kV transmission lines, which run between Mica Generating Station and the Nicola Substation near Merritt. The capacitor station will increase the transmission capacity of the lines and allow the Mica Generating Station to securely deliver its full station output when the new generating Units 5 and 6 are in place.		

VANCOUVER CITY CENTRAL TRANSMISSION	March 2014 In-Service	$171 Total cost ($ millions)
Built an enclosed 230/12 kV substation in the Mt. Pleasant area of Vancouver and two new underground 230 kV transmission lines connecting the new substation to the existing transmission network to serve growing loads in the Mt. Pleasant/False Creek area and maintain a reliable supply of electricity to other areas of Vancouver.		

ONGOING AND PLANNED[1,2]

MICA SF_6 GAS INSULATED SWITCHGEAR REPLACEMENT PROJECT	2014 Targeted completion	$199 Total cost ($ millions)	$162 LTD cost ($ millions)
Replace the switchgear system at the Mica Generating Station and install additional switchgear capacity to accommodate the future Units 5 and 6 additions to ensure the reliability of this key generating station and reduce SF_6 (a greenhouse gas) leakage. The switchgear system, energized at 500 kV, conducts energy from the Mica underground powerhouse to the surface, where it transitions to transmission lines.			

NORTHWEST TRANSMISSION LINE PROJECT	2014 Targeted completion	$746 Total cost* ($ millions)	$603 LTD cost ($ millions)
Construct an approximately 340 km, 287 kV transmission line between Skeena Substation near Terrace and a new substation to be built near Bob Quinn Lake to ensure a reliable supply of clean power to potential industrial developments in the area, and provide a secure interconnection point for clean generation projects. *Total cost represents the gross cost of the project and has not been netted for contributions, which total $220 million from the Federal Government and a customer prior to the in-service date. Additional payments will be received from a customer for 20 years after the in-service date.			

ISKUT EXTENSION PROJECT	2015 Targeted completion	$180 Total cost* ($ millions)	$24 LTD cost ($ millions)
Construct a 92 km, 287 kV transmission extension, plus a 16 km distribution line from Bob Quinn Substation. The transmission line would terminate at a new substation at Tatoga Lake with the 16 km, 25 kV distribution line continuing to Iskut. *The total cost represents the gross cost of the project and has not been netted to reflect contributions of $40 million from a customer.			

[1] *The capital expenditure amounts do not include dismantling or asset retirement costs.*

[2] *Life to date (LTD) costs to March 31, 2014.*

MERRITT AREA TRANSMISSION PROJECT	2014 Targeted completion	$65 Total cost ($ millions)	$19 LTD cost ($ millions)

Construct a new 138-kV transmission line between the Merritt and Highland substations, expand the Merritt Substation and add new equipment at the Highland Substation to meet the increased demand for power in the Merritt area.

DAWSON CREEK/ CHETWYND AREA TRANSMISSION PROJECT	2015 Targeted completion	$296 Total cost ($ millions)	$85 LTD cost ($ millions)

The project will expand the Peace Region 230kV transmission system to the Dawson Creek/Chetwynd area to supply the high area load growth. The solution will include the construction of new 230kV lines between Dawson Creek and Bear Mountain Terminal (BMT), and from BMT to a new substation called Sundance Lake Substation, located approximately 19 km east of Chetwynd. Change from the total cost in the 2013/14-2015/16 Service Plan reflects increase in cost estimates for labour and materials and additional project consultation requested by the British Columbia Utilities Commission (BCUC). The total cost estimate is within the range provided in the project's CPCN application update in March 2012.

G.M.SHRUM UNITS 1 TO 5 TURBINE REPLACEMENT	2015 Targeted completion	$272 Total cost ($ millions)	$120 LTD cost ($ millions)

Replace the Units 1 to 5 turbines to reduce the risk of runner failure, decrease maintenance costs, and improve operating efficiency.

LONG BEACH AREA RE-INFORCEMENT	2015 Targeted completion	$56 Total cost ($ millions)	$6 LTD cost ($ millions)

Expansion of Long Beach and Great Central Lake Substations with two new transformers at each and capacitor banks at Long Beach to support the load growth and provide voltage support in the area.

SURREY AREA SUBSTATION PROJECT	2015 Targeted completion	$94 Total cost ($ millions)	$16 LTD cost ($ millions)

Construct a new 200 MVA 230/25 kV substation in the Fleetwood area of Surrey. The supply to the station will be from the nearby 230 kV transmission line and will allow for increased station capacity to 400 MVA.

INTERIOR TO LOWER MAINLAND PROJECT	2015 Targeted completion	$725 Total cost ($ millions)	$415 LTD cost ($ millions)

Construct a new 500 kV transmission line, approximately 247 km in length, between the Nicola Substation near Merritt and the Meridian Substation in Coquitlam and build a new series capacitor station at Ruby Creek near Agassiz to help meet domestic load growth in the Lower Mainland.

SMART METERING & INFRASTRUCTURE PROGRAM	2015 Targeted completion	$930* Total cost ($ millions)	$677 LTD cost ($ millions)

The Smart Metering and Infrastructure Program includes the installation of 1.9 million smart meters in homes and businesses across the province, an advanced telecommunications infrastructure to support electricity system management and customer applications, and information technology to support customer billing, load forecasting and outage management systems.

** Smart Metering & Infrastructure Program amount includes both capital costs and operating expenditures subject to regulatory deferral.*

HUGH KEENLEYSIDE SPILLWAY GATE RELIABILITY UPGRADE	2015 Targeted completion	$123 Total cost ($ millions)	$72 LTD cost ($ millions)

Upgrade the spillway gates* at the Hugh Keenleyside Dam to increase public and employee safety by ensuring the gates meet flood discharge reliability requirements.

** Spillway gates control the amount of water that can be discharged from the reservoir. They are generally used in times of flood to pass high inflows.*

UPPER COLUMBIA CAPACITY ADDITIONS AT MICA - UNITS 5&6	2015 Targeted completion	$714 Total cost ($ millions)	$415 LTD cost ($ millions)

Install two additional 500 megawatt (MW) generating units into existing unit bays at the Mica Generating Station. The new units are similar to the four existing units, but with more efficient turbines.

BIG BEND SUBSTATION	2016 Targeted completion	$56 Total cost ($ millions)	$14 LTD cost ($ millions)

The South Burnaby, Big Bend area requires a new, 100 MVA, 69/12 kV substation to meet local residential and commercial load growth.

RUSKIN DAM SAFETY AND POWERHOUSE UPGRADE	2017 Targeted completion	$748 Total cost ($ millions)	$220 LTD cost ($ millions)

Improve seismically deficient dam and rehabilitation/ replacement of powerhouse equipment that was brought into service between 1930 and 1950. It is expected to take six years to complete and includes: reinforcement of the right embankment; seismic upgrade of the dam and water intakes; powerhouse upgrades; and, relocation of the switchyard. Once completed, the upgraded facility will be reliable and safe and will produce enough electricity to serve more than 33,000 homes.

JOHN HART GENERATING STATION REPLACEMENT	2019 Targeted completion	$1,093 Total cost ($ millions)	$145 LTD cost ($ millions)

Replace the existing six-unit 126 MW generating station (in operation since 1947) and add integrated emergency bypass capability to ensure reliable long-term generation and to mitigate earthquake risk and environmental risk to fish and fish habitat.

SITE C CLEAN ENERGY PROJECT	2023* Targeted completion	$7,900 Total cost ($ millions)	$338 (deferred capital LTD cost ($ millions)

Site C is a proposed third dam and 1,100 MW hydroelectric generating station on the Peace River approximately seven kilometres southwest of Fort St. John. It would be capable of producing approximately 5,100 gigawatt-hours of electricity annually and would deliver firm electricity with a high degree of flexibility. The Site C project is currently undergoing a cooperative federal-provincial environmental assessment, which is expected to be completed in fall 2014. Subject to approvals, Site C would provide clean, renewable and cost-effective power in B.C. for more than 100 years.

** Planned in-service date for all units. This timeline reflects the project's current regulatory schedule and is subject to change based on a review of the construction schedule.*

CONTEMPLATED PROJECTS OVER $50 MILLION

BC Hydro is contemplating the following projects over $50 million commencing during fiscal 2015–fiscal 2017, listed in alphabetical order. These projects are in the initial project phases; scope, final cost and benefit assessment, and completion dates are still to be determined. These projects have not yet been approved by the Board of Directors.

BRIDGE RIVER 2 UNITS 5 AND 6 REHABILITATION

Restore Bridge River 2 Units 5 and 6 (commissioned over 60 years ago) to "as new condition." This would address known major component deficiencies and enable the units to run at full capacity (currently derated from 70 MW to 60 MW).

CHEAKAMUS UNIT 1 AND UNIT 2 GENERATOR REPLACEMENT

Replace the two generators at Cheakamus generating station (commissioned over 50 years ago) to address poor condition and known deficiencies. Replacing the generators will increase the capacity of each unit from 70 MW to 90 MW.

DOWNTOWN VANCOUVER REDEVELOPMENT PROGRAM

Upgrade and expand the transmission and distribution network serving downtown Vancouver over the next 20 to 30 years to improve reliability and seismic resiliency. The project includes the addition of a new transmission cable coming into the downtown core, the construction of new substations, and the refurbishment and/or replacement of the existing substations. The project also includes converting the existing distribution system from a 12 kV dual radial system to a 25 kV open-loop system.

G.M. SHRUM G1-G10 CONTROL SYSTEM UPGRADE

The condition of the legacy controls for GMS generating units, which were originally installed in the 1960s and 1970s, is of growing concern due to increasing maintenance requirements, lack of spare parts availability and decreasing reliability. The controls are well beyond their expected life, cause operating problems and increase the risk of damage to major equipment.

HORNE PAYNE SUBSTATION UPGRADE

Expand the Horne Payne Substation with the addition of two 230/25kV, 150MVA transformers, gas-insulated (GIS) feeder sections, and a new control building. This project will increase the firm capacity of the substation, add needed feeder positions, facilitate the gradual conversion of the area supply voltage from 12kV to 25kV, and allow for the implementation of an open-loop distribution system.

JOHN HART DAM SEISMIC UPGRADE

Upgrade the John Hart Dam to reliably withstand moderate to severe earthquake loadings and meet normal operations criteria post-earthquake.

LADORE UPGRADE DAM SPILLWAY GATES

Reduce the risk of failure of the spillway gates and hoist structure due to a seismic event. Improve post-seismic operability in order to prevent the subsequent uncontrolled release of water into the downstream John Hart Reservoir and maintain reservoir control in the system.

METRO NORTH TRANSMISSION STUDY

A new 230 kV transmission line(s) is proposed between Coquitlam and Vancouver to address load growth in the Metro Vancouver area and to strengthen the reliability of the network.

NORTHWEST SUBSTATION UPGRADES PROJECT

Carry out modifications, upgrades and additions to five substations in the northwest (Williston, Glenannan, Telkwa, Skeena and Minette) to accommodate the interconnection of industrial loads in the northwest including LNG Canada's Liquefied Natural Gas facility expected to come on line in early 2020.

PEACE REGION ELECTRIC SUPPLY

Increase transmission capacity to the South Peace area by providing a second 230 kV supply to Dawson Creek in response to the significant load growth in the area, mainly from the gas production industry.

PRINCE GEORGE TO TERRACE CAPACITATORS
The Prince George to Terrace Capacitors project will increase the capacity of the 500kV circuit supplying the north coast areas. This will increase the transfer capacity by up to approximately 60 per cent through the addition of reactive compensation. This additional capacity is required to provide capacity for industrial loads expected interconnect in the Northwest. The timing of the Prince George to Terrace Capacitors project is linked to the interconnection of LNG Canada's Liquefied Natural Gas plant that is scheduled for early 2020.

REVELSTOKE UNIT 6 INSTALLATION
Supply and install an approximately 500 MW unit in the existing empty Unit 6 bay at Revelstoke Generating station to add capacity to the BC Hydro system. Revelstoke Unit 6 is identified as a contingency resource in BC Hydro's 2013 Integrated Resource Plan (IRP).

TERRACE - KITIMAT TRANSMISSION PROJECT
Replace the existing transmission line serving the Kitimat area that has reached the end of its serviceable life. This project would replace the 60km transmission line that runs between Skeena and Minette substations and the 3km transmission line that runs between Minette and Kitimat Substations with new 287kV lines on a new right of way. Both of these lines have been de-rated due to defects and deficiencies, and cannot supply current and forecast load demands.

W.A.C. BENNETT DAM RIP-RAP UPGRADE
The W.A.C. Bennett Dam Rip-rap has degraded since its completion in 1968. The project will rebuild the upstream slope to ensure there is adequate protection and shielding to the embankment dam from the wind generated waves.

REPORT ON PERFORMANCE

BC Hydro met or exceeded 17 of 22 reported Service Plan performance metrics in fiscal 2014.

STRATEGIC OBJECTIVES	PERFORMANCE MEASURE	F2012 Actual	F2013 Actual	F2014 Target	F2014 Actual	Status	F2015 Target	F2016 Target	F2017 Target
SAFELY KEEP THE LIGHTS ON	Zero Fatality & Serious Injury (Loss of life or the injury has resulted in a permanent disability)	0	1	0	0	○	0	0	0
	Severity (Number of calendar days lost due to injury per 200,000 hours worked)	27.4	45.1	27.0	28.9	●	25.0	24.0	23.0
	All Injury Frequency (Number of employee injury incidents per 200,000 hours worked)	1.7	2.1	1.7	2.0	●	1.6	1.5	1.5
	Safety Taskforce Recommendation Implementation[2] (Number of recommendations fully implemented and in sustainment out of 21 total)	NR	NR	7	7	○	12	16	21
	CAIDI[3] (hours) – Average Interruption in hours per interrupted customer	2.27	2.12	2.30	2.30	○	2.25	2.20	2.20
	SAIFI[3] (frequency) – Number of sustained disruptions per year	1.58	1.29	1.45	1.56	○	1.40	1.40	1.40
	CEMI-4[3] (%) – Customers experiencing four or more outages	12.5	9.1	11.0	12.35	●	11.0	11.0	11.0
	Winter Generation Availability Factor (%)	96.8	98.1	96.4	96.8	○	96.4	96.4	96.4
SUCCEED THROUGH RELATIONSHIPS	CSAT Index (% of customers satisfied or very satisfied)—Customer Satisfaction Index	87	86	85	85	○	85	85	85
	Billing Accuracy (% of accurate bills)	98.4	98.5	98.4	99.1	○	99.0	99.1	99.2
	First Call Resolution (% of customer calls resolved first time)	74.2	68.0	72.0	71.0	○	73.0	73.0	73.0
	Progressive Aboriginal Relations Designation	Silver	Gold	Gold	Gold	○	Gold	Gold	Gold
MIND OUR FOOTPRINT	Demand Side Management (DSM) (GWh/year)	3,424	4,460	5,100[4]	4,776	●	5,500	6,300	6,700
	Electricity Production GHG Emissions[5] (kilotonnes CO_2e)	560	631	710	730	●	740	870	870
	Carbon Neutral Program Emissions (kilotonnes CO_2e)	30.0	28.8	30.0	27.0	○	29.0	29.0	29.0
	Clean Energy (%)	98.1	98.2	93.0	97.1	○	93.0	93.0	93.0
FOSTER ECONOMIC DEVELOPMENT	BC Hydro Capital Spend ($ millions within B.C.)	1,853	1,865	1,963[6]	1,968	○	NR	NR	NR

○ *Target met* ● *Target not met*

STRATEGIC OBJECTIVES	PERFORMANCE MEASURE	F2012 Actual	F2013 Actual	F2014 Target	F2014 Actual	Status	F2015 Target	F2016 Target	F2017 Target
MAINTAIN COMPETITIVE RATES	Competitive Rates	1st Quartile	1st Quartile	1st Quartile	1st Quartile	●	1st Quartile	1st Quartile	1st Quartile
	Net Income ($ million)	558	509	545	549	●	582	652	701
	Operating Costs[7] ($ million)	665	705	699	702	●	706	713	730
	Debt to Equity (%)[8]	80/20	80/20	80/20	80/20	●	NR	NR	NR
ENGAGE A SAFE & EMPOWERED TEAM	Employee Engagement (%)[9]	—	78	79	79	●	See note 9		

Notes:

1 *Fiscal 2015 to fiscal 2017 performance targets as published in the BC Hydro 2014/15–2016/17 Service Plan. Fiscal 2014 targets remain consistent with the 2013/14–2015/16 Service Plan.*

2 *This is a new metric for fiscal 2014. This is a cumulative metric with one recommendation implemented in fiscal 2013, and the additional six implemented in fiscal 2014.*

3 *Performance within +/- 10 per cent is considered acceptable for the reliability targets given the wide range of potential disruptions to the electrical system. BC Hydro measures reliability under normal circumstances, which excludes major events. A major event is defined as an uncontrollable event (e.g. windstorm or forest fire) that results in more than 70,000 customer hours lost.*

4 *This is a cumulative target of energy savings since fiscal 2008. Target in the 2013/14-2015/16 Service Plan was 5,100 GWh/yr. The fiscal 2014 target was revised to 5,000 in the current Service Plan (2014/15 to 2016/17) in order to align with the 2013 Integrated Resource Plan.*

5 *BC Hydro is reporting its greenhouse gas (GHG) emissions by calendar year instead of fiscal year to align with GHG emissions reports filed under the Canadian Environmental Protection Act, 1999, the B.C. Reporting Regulation and the B.C. Carbon Neutral Reporting Regulation.*

6 *BC Hydro capital spending in British Columbia is the total capital spend adjusted for estimated spend within British Columbia. Targets for Capital Spend in B.C. in BC Hydro's Service Plan are set based on total forecast BC Hydro capital expenditures adjusted to exclude estimates of major capital purchases from outside of B.C. Actual expenditures are net of government contributions for the Northwest Transmission Line project. The adjusted target to reflect government contributions is 1,886.*

7 *Operating costs are defined as personnel, materials and external services expenses included in income, that are incurred in the day-to-day operation of BC Hydro's electric utility, net of recoveries, capitalized costs and reclassification adjustment.*

8 *As part of the 10 year plan, the Province will restrict the amount of dividends received from BC Hydro starting in fiscal 2018 until such time as the debt to equity ratio reaches 60:40. BC Hydro does not anticipate reaching the debt to equity ratio of 60:40 during the 10 year period. As a result of this change, the debt to equity ratio will be removed as a performance measure effective fiscal 2015.*

9 *The target for each of fiscal 2015, fiscal 2016, and fiscal 2017 is to meet/exceed the benchmark of the Towers Watson Global Utilities norm for that year.*

Safely and reliably meet the electricity needs of our customers through integrated planning and technology, and in the operation, maintenance and advancement of our system.

STRATEGIES IN THE 2013/14 – 2015/16 SERVICE PLAN

- To continue to implement the recommendations of the Safety Taskforce, complementing and supporting the existing Four Pillar Safety Plan. Develop leading metrics reflective of progress and outcomes from the Plans.[1]
- Systematically identify and, where possible, reduce the number of hazards through work-planning activities and work procedure development.
- Increase integration of job-safety planning into day-to-day work for all operating facilities and all operational activities.
- Participate in regional planning initiatives to identify opportunities to increase regional transmission capacity and advance work on major transmission infrastructure projects.
- Continue implementation of a comprehensive, long term reliability strategy to improve the system and customer reliability.
- Invest in projects that utilize new technologies that support safe and reliable operations, such as: the Smart Metering and Infrastructure Program, Distribution Management System, Enterprise Geographic Information System, and other business intelligence solutions.
- Continue to effectively manage dam safety issues, risks and regulatory requirements.

FISCAL 2014 SUMMARY

SAFETY IS A FUNDAMENTAL VALUE

Safely and reliably meeting our customers' electricity needs is the focus of BC Hydro's workforce supporting the generation, transmission and distribution of electricity.

The Safety Taskforce was established in 2010 following an employee fatality. BC Hydro began implementing the recommendations of the Safety Taskforce in 2011. Work started in fiscal 2012 by dedicated implementation teams or through direct implementation by the Business Groups. All the recommendations are expected to be implemented by end of fiscal 2017.

Producing and delivering electricity safely involves keeping a well-maintained electrical system that reduces the potential for harm to workers and the public. This includes preventing employee and contractor injuries, public education on hazards related to our system, and anticipating and responding to the impacts of natural disasters, such as storms, floods and forest fires.

Following a marked increase in public near miss incident reporting over the past year, we are seeking to improve safety around our assets to help prevent inadvertent contact with the electrical system by contractors and members of the public. As part of this, we are reviewing internal processes and have jointly developed a BC Hydro / WorkSafeBC public safety messaging campaign that will be implemented in fiscal 2015 with public safety video spots focusing on inadvertent contact with the electrical system.

BC Hydro's *Life Saving Rules* support our focus on addressing hazards and support our goal of zero fatalities and serious injuries.

---

[1] BC Hydro updated the Four Pillars Safety Plan in fiscal 2014 reflecting the focus of the Safety Taskforce Recommendations (many of the Four Pillars Safety Plan aspects are embedded within the Safety Taskforce Recommendations), the new Safety Policy and the risk analysis results. The 2014/15-2016/17 Service Plan reflects these changes and the strategy has been simplified to *Implement the Recommendations of the Safety Taskforce*.

INVESTING TO ENSURE RELIABILITY

In addition to ensuring the safety of our employees, contractors and the public, BC Hydro is also responsible for reliably providing power. This requires ensuring the health of our infrastructure, identifying future supply to meet customers' needs, and putting in place new technologies and work methods to support the reliability and safety of our system.

Providing highly reliable service to all customers is a challenge given the size of our service area, our predominantly overhead distribution system, and the abundance of trees and rough terrain throughout the province. BC Hydro has two to three times as many trees per overhead pole kilometer as the North American average, and trees, together with adverse weather, account for half of the annual lost customer hours. This environment significantly affects our ability to achieve higher levels of reliability while balancing the need to continue to provide competitively priced power.

Reliability-focused programs in fiscal 2014 contributed directly to our reliability performance including our vegetation management hazard tree program, and prioritized investment in the worst performing circuits. We continue to find solutions, such as automation through better technology, to improve circuits with customers having multiple interruptions. We are also improving circuit tie points, and continued transmission right-of-way control and maintenance.

Short-term and medium-term strategies to improve reliability include leveraging the smart metering infrastructure and data, as well as our distribution management system, to increase efficiencies and the level of automation for development of a more flexible distribution system. The completion of initiatives that are driven by the need to address load growth, energy conservation, and end-of-life asset replacement, is also expected to improve customer reliability.

SAFETY

WHAT WE MEASURE AND WHY

ZERO EMPLOYEE FATALITY AND SERIOUS INJURY, SEVERITY & ALL INJURY FREQUENCY

The measure of zero employee fatalities or serious injuries is a reflection of our commitment to eliminating Level 1 injury incidents. Level 1 incidents are when there has either been a loss of life or the injury has resulted in a permanent disability (and a disability pension has been received or is expected). The measure of serious injury is unique to BC Hydro and thus is not benchmarked against other Canadian Electricity Association (CEA) member utilities. However, the CEA does report on fatalities. BC Hydro had one of the four fatalities among CEA members in the five-year period from 2009 to 2013. We also have had eight on the job employee fatalities since 1999.

BC Hydro also measures Severity and All Injury Frequency, which are standard CEA measures. Severity is defined as the number of calendar days lost due to injury per 200,000 hours worked. The Severity metric does not include data on fatal incidents; however, one or two injuries can have a major impact on Severity. All Injury Frequency is defined as total number of employee medical aids and lost time injuries per 200,000 hours worked. Medical aid injuries are those where a medical practitioner has rendered services beyond the level defined as "first aid" and the employee has not been absent from work after the day of injury. Lost time injuries are those where the employee is absent beyond the day of injury.

Both Severity and All Injury Frequency measures are, as defined in the CEA Standard, generally harmonized with the U.S. Occupational Safety and Health Administration Standards for safety statistics. The data source for all safety performance metrics are incidents reported through the Incident Management System. To ensure accuracy and reliability of the data, each incident is reviewed to ensure that it meets the CEA reporting criteria, the correct level and type has been assigned, and the appropriate calendar days lost have been assigned to lost time injuries. This approach does exclude a small number of accepted WorkSafeBC claims that do not meet the CEA reporting criteria.

BC Hydro benchmarks its Severity and All Injury Frequency performance against available CEA composite results. For the 2013 calendar year, the CEA composite Severity result was 19.5, and the CEA Group 1 utilities (utilities with greater than 1,500 employees) composite result was 21.7, compared to BC Hydro's 2013 calendar year result of 30.5. BC Hydro consistently has results in the fourth quartile compared to other CEA Group 1 utilities. For the 2013 calendar year, the CEA composite All Injury Frequency result was 1.7, and the CEA Group 1 utilities composite result was 1.8, compared to BC Hydro's 2013 calendar year result of 1.8. BC Hydro's result for 2013 was in the second quartile compared to other CEA Group 1 utilities. In previous years, BC Hydro's results were usually in alignment with other CEA Group 1 utilities, with results in the second quartile.

SAFETY TASKFORCE RECOMMENDATIONS IMPLEMENTATION

The taskforce's 21 recommendations, combined with safety programs already underway, are intended to improve and sustain our safety performance. This metric demonstrates our commitment to ensuring the taskforce's recommendations are implemented and sustained. This metric is unique to BC Hydro and cannot be benchmarked against other organizations.

OUR PERFORMANCE

In fiscal 2014, BC Hydro met its targets for not having any fatalities or serious employee injuries and for the new corporate measure – Safety Taskforce Recommendation implementation – with seven recommendations completed. We did not meet our safety performance targets in the areas of All Injury Frequency and Severity; however, our statistics are showing that we have started to make a positive shift in the frequency of serious injuries and our severity metric shows improvement over fiscal 2013.

PERFORMANCE MEASURES

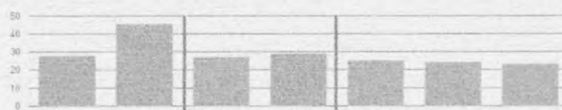
ZERO FATALITY AND SERIOUS INJURY

There has either been a loss of life or an injury resulting in a permanent disability.

ACTUAL F2012	ACTUAL F2013	TARGET F2014	ACTUAL F2014	TARGET F2015[1]	TARGET F2016[1]	TARGET F2017[1]
0	1	0	0	0	0	0

SEVERITY

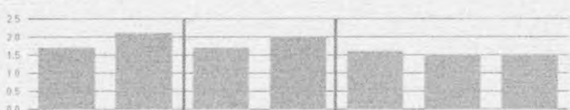
Number of days lost due to injury per 200,000 hours, based on actual hours worked *(lower is better)*



ACTUAL F2012	ACTUAL F2013	TARGET F2014	ACTUAL F2014	TARGET F2015[1]	TARGET F2016[1]	TARGET F2017[1]
27.4	45.1	27.0	28.9	25.0	24.0	23.0

ALL INJURY FREQUENCY

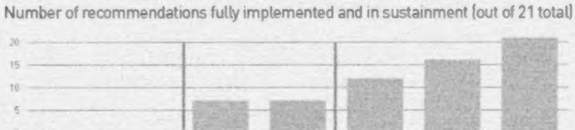
Number of injuries per 200,000 hours, based on actual hours worked *(lower is better)*



ACTUAL F2012	ACTUAL F2013	TARGET F2014	ACTUAL F2014	TARGET F2015[1]	TARGET F2016[1]	TARGET F2017[1]
1.7	2.1	1.7	2.0	1.6	1.5	1.5

SAFETY TASKFORCE RECOMMENDATIONS IMPLEMENTATION[2]

Number of recommendations fully implemented and in sustainment (out of 21 total)



ACTUAL F2012	ACTUAL F2013	TARGET F2014	ACTUAL F2014	TARGET F2015[1]	TARGET F2016[1]	TARGET F2017[1]
NR	NR	7	7	12	16	21

[1] *Fiscal 2015 to fiscal 2017 performance targets as published in the BC Hydro 2014/15–2016/17 Service Plan.*

[2] *This is a new metric for fiscal 2014. This is a cumulative metric with one recommendation implemented in fiscal 2013, and the additional six implemented in fiscal 2014.*

Note: *It is important to note that with over half of our medical aid and lost time injuries being the result of body mechanics, the factors that influence our Severity and All Injury Frequency results are not the same as those influencing our results for fatalities and serious injuries.*

The Safety Taskforce Recommendation implementation measure is staged over multiple years to ensure that change can be sustained and that we're building a foundation in the organization. This year, six Safety Taskforce Recommendations were implemented and transitioned to sustainment, bringing the cumulative result to seven:

- Life Saving Rules/Just Culture
- Employee Engagement Principles
- Courage to Intervene
- Safety Advocates
- Joint Health and Safety Committees
- Safety Reporting
- Job Planning (completed in fiscal 2013)

Each recommendation was implemented using a variety of engagement approaches with specific objectives and measures to support sustainment. For example, to support full buy-in with front line operations, the Life Saving Rules/ Just Culture engagement strategy entailed a full-time team of operational employees who worked for 18 months to develop and roll out the Life Saving Rules/Just Culture approach company-wide. During this time, this team also used focus groups, and engagement of field personnel and technical and safety subject matter experts.

In the area of front line operations, the recommended Safety Advocate role was implemented and six employees are now fully deployed in the field to support procedures, rule interpretations, and job planning predominantly in the electrical safety area.

BC Hydro adjusted its Joint Health and Safety Committee structure to ensure compliance with WorkSafeBC regulation and by the end of the fiscal year, the committee structure was fully functioning in accordance with the regulation.

One of the taskforce's recommendations is an Integrated Safety, Health & Environment Management System, which was initiated as a project in fiscal 2014. The project will bring together multiple systems and embed safety, health and environment processes in the business to reduce the frequency and severity of incidents and impacts to people, property, and the environment; ensure due diligence in meeting compliance; and make the system easy to access and use in the field.

BC Hydro's Severity rate of 28.9 for fiscal 2014 is above the Service Plan target of 27 but is favourable compared to the fiscal 2013 result of 45.1. Of the 54 injuries in fiscal 2014 resulting in lost time, four of the injured workers have yet to return to work. Thirteen of the 54 lost time injuries resulted in 30 or more calendar days lost and represent 71 per cent of the Severity rate results. Of these 13 lost time injuries resulting in 30 or more calendar days lost, the four most serious incidents account for over 36 per cent of the Severity rate. A further 39 per cent of the Severity rate is due to 16 of the 54 incidents, all of which relate to injuries from body mechanics (slips, trips and falls, lifting, pushing and pulling, and sprains, strains or ruptures from voluntary or involuntary bodily motions).

BC Hydro's All Injury Frequency result of 2.0 for fiscal 2014 is above our target of 1.7 and slightly below the fiscal 2013 result of 2.1.

RELIABILITY

WHAT WE MEASURE AND WHY

CAIDI, SAIFI AND CEMI-4

CAIDI and SAIFI are utility industry standard metrics that measure the average duration of interruption per interrupted customer, and how many sustained interruptions (longer than one minute) an average customer will experience over the course of a year, respectively. CEMI-4 is a standard metric that measures the percentage of customers experiencing four or more outages over the course of a fiscal year. CEMI is a relatively new standard measure not widely benchmarked externally as utilities are at varying stages in their development and adoption of this metric.

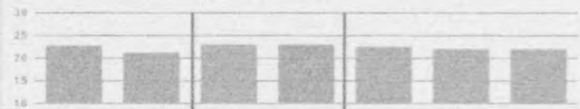
Annually, circuits are benchmarked to prioritize investment for sustained reliability improvement on the worst performing circuits. On a monthly basis, the most significant outages are reviewed to ensure accuracy of data, effectiveness of restoration actions, and to better understand vulnerabilities. As a second check for accuracy, trends in recent performance measures are compared against past results and forecast performance. The Reliability Improvement Team reviews the monthly performance measures and takes action when actual performance deviates from forecast.

The data gathered to measure our three reliability measures – CAIDI, SAIFI & CEMI-4 – is collected and validated in a process that starts with operational staff who record the start and end time of each power outage as well as the cause. Based on the location of the outage, the number of customers impacted is calculated automatically. This information is collected in a centralized database that allows outage records to be reviewed by managers each day to ensure accuracy. Outages that impact a significant number of customers or involve lengthy repair times require a formal outage report to be written by an engineer and approved by management. As BC Hydro completes the implementation of the Smart Metering Program, outage performance measures will be calculated automatically.

BC Hydro measures reliability under normal operating conditions, because we cannot predict uncontrollable, major weather events. Annually, BC Hydro participates in Transmission and Distribution benchmarking surveys conducted by First Quartile Consulting, and the Distribution Service Continuity survey conducted by the CEA. Our reliability targets are based on specific values; however performance within a 10 per cent bandwidth of our targets is considered acceptable given the wide range of variations in weather patterns and other uncontrollable elements that can significantly disrupt the electrical system.

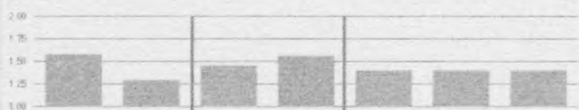
PERFORMANCE MEASURES

CAIDI[1]—Average interruption in hours per interrupted customer *(lower is better)*



ACTUAL F2012	ACTUAL F2013	TARGET F2014	ACTUAL F2014	TARGET F2015[2]	TARGET F2016[2]	TARGET F2017[2]
2.27	2.12	2.30	2.30	2.25	2.20	2.20

SAIFI[1]—Number of interruptions per customer per year *(lower is better)*

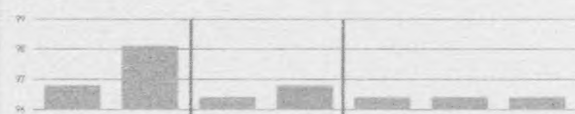


ACTUAL F2012	ACTUAL F2013	TARGET F2014	ACTUAL F2014	TARGET F2015[2]	TARGET F2016[2]	TARGET F2017[2]
1.58	1.29	1.45	1.56	1.40	1.40	1.40

CEMI-4[1] (%)—Percentage of customers experiencing 4 or more outages *(lower is better)*

ACTUAL F2012	ACTUAL F2013	TARGET F2014	ACTUAL F2014	TARGET F2015[2]	TARGET F2016[2]	TARGET F2017[2]
12.5	9.1	11.0	12.35	11.0	11.0	11.0

WINTER GENERATION AVAILABILITY FACTOR[1] (%)—
Heritage Asset units >20 MW available to generate electricity, excluding certain planned capital and maintenance outages *(higher is better)*



ACTUAL F2012	ACTUAL F2013	TARGET F2014	ACTUAL F2014	TARGET F2015[2]	TARGET F2016[2]	TARGET F2017[2]
96.8	98.1	96.4	96.8	96.4	96.4	96.4

[1] *Performance within +/- 10 per cent is considered acceptable for the reliability targets given the wide range of potential disruptions to the electrical system. BC Hydro measures reliability under normal circumstances, which excludes major events. A major event is defined as an uncontrollable event (e.g. windstorm or forest fire) that results in more than 70,000 customer hours lost.*

[2] *Fiscal 2015 to fiscal 2017 performance targets as published in the BC Hydro 2014/15–2016/17 Service Plan.*

WINTER GENERATION AVAILABILITY FACTOR

BC Hydro focuses on Winter Generation Availability Factor to manage the availability of generation during the critical winter period when customer loads are most likely to reach their annual peaks, and to ensure all BC Hydro generating units will remain in-service barring a forced outage or urgent maintenance.

Winter Generation Availability Factor is a percentage of Heritage Asset units in the system greater than 20 MW and available to generate electricity (total hours available for service/total hours), excluding certain planned capital and maintenance outages, during the critical peak load period of November 15 to February 15. BC Hydro is not aware of any external benchmarks suitable for comparison with the Winter Generation Availability Factor, and instead uses historical trend information to track performance.

OUR PERFORMANCE

In fiscal 2014, we met our annual reliability targets for CAIDI and SAIFI, and were slightly above the CEMI-4 target. Past investments in reliability have led to a lower than historical average number of outages caused by adverse weather, trees, and equipment failure contributing to the largely favourable reliability performance.

The actual Winter Generation Availability Factor for fiscal 2014 was 96.8 per cent, which is higher than the 96.4 per cent target. Although there were several forced outages at several of our facilities throughout the winter months, the remainder of the hydro generation units performed very well throughout the winter period. There were a number of planned capital and maintenance outages throughout the system, which we exclude from the Winter Generation Availability Factor calculation.

Gain support for our work by building trusted relationships with First Nations, customers, suppliers and the communities we serve.

STRATEGIES IN THE 2013/14 – 2015/16 SERVICE PLAN

- Sustain BC Hydro's gold-level certification under the Progressive Aboriginal Relations (PAR) program by maintaining leading practices in the areas of Aboriginal employment, business development, capacity development and community engagement.
- Obtain project and operational certainty through various strategies, including continuing to build collaborative and enduring relationships with First Nations.
- Strengthen BC Hydro's understanding of customers' needs and expectations through customer engagement, targeted segmentation and benchmarking.
- Increase the efficiency, consistency and quality of customer integration of all customer channels.
- Educate, support and encourage regional districts, municipalities and large-scale developers in creating integrated, community-wide energy strategies.
- Implement recommendations from our supplier engagement review to improve how we engage with our suppliers.

FISCAL 2014 SUMMARY

BC Hydro works to build and improve relationships with customers and suppliers. The organization's goals include delivering outstanding value and service to our customers and being a customer of choice for our suppliers.

ABORIGINAL RELATIONSHIPS AND COLLABORATION

BC Hydro continues as a gold-level certified company within the Canadian Council of Aboriginal Business' Progressive Aboriginal Program.

Through fiscal 2014, BC Hydro actively worked to create economic opportunities for First Nations through contracting opportunities. For example, we have entered into an agreement with the Songhees and Esquimalt First Nations to assist with BC Hydro's cleanup efforts at Rock Bay in Victoria, the former site of a coal gasification plant owned by our predecessor companies. We are also working with We Wai Kai and Wei Wai Kum First Nations on a salmon passage project in the vicinity of the John Hart Generating Station.

BC Hydro is honoured to have been invited to participate in numerous Aboriginal events and celebrations during fiscal 2014. In June, our Hazelton crew took part in a Gitxsan cultural event by transporting a traditional totem pole from its carving place to its erection site, near Kispiox, on National Aboriginal Day. In September, BC Hydro employees walked, paddled and volunteered their time in support of Reconciliation Week, held in Vancouver to recognize the multi-generational impacts of Indian residential schools in Canada.

These relationships continue to uncover new opportunities for collaboration and reduce financial, legal and operating risks for BC Hydro associated with the outstanding claims of Aboriginal rights and title.

WORKING WITH LOCAL COMMUNITIES

BC Hydro is focussed on communities, including local governments, regional districts and constituents, to advance shared goals by working together. BC Hydro's Power Smart and Community Relations programs help gain support for work in communities where BC Hydro operates or has projects underway.

TOOLS FOR OUR CUSTOMERS

We improved our customers' online experience by completing a number of initiatives aimed at improving the self-service experience and enabling long term organizational and customer benefits. Over half of the interactions initiated by our customers are now taking place via the on-line channel. The number of customers utilizing paperless billing increased steadily during the year and the fiscal year ended with 30 per cent of our customers choosing to receive their bill electronically.

WHAT WE MEASURE AND WHY

CUSTOMER SATISFACTION (CSAT)

CSAT is the percentage of customers—residential, small and medium-sized businesses and key accounts—who are satisfied or very satisfied with BC Hydro in five equally weighted areas: providing reliable power, value for money, commitment to customer service, acting in the best interests of British Columbians, and efforts to communicate with customers and communities.

BC Hydro maintains a minimum threshold target of 85 per cent for CSAT to ensure we have strong customer support. BC Hydro benchmarks against leading regional service providers and other electric utilities in an effort to better understand our performance relative to customer perceptions and understand what is needed to be a leader in our industry and the province. Benchmarking results to date demonstrate BC Hydro compares well against both non-electric utility service providers and other electric utilities.

2013 AWARDS AND RECOGNITION

By focusing on our values, BC Hydro has received several awards and recognition over the past year from independent third parties for our performance in areas of workplace and corporate sustainability. Listed below are some of the awards and recognition we received in fiscal 2014:

- Top 10 BC's Best Loved Brands from Ipsos North America and *BC Business*
- 2014 Best 50 Corporate Citizens in Canada from *Corporate Knights*
- Canadian Electrical Association 2013 Sustainability Electricity Award for our Lead by Example conservation program in the category of economic excellence.
- 2014 B.C.'s Top Employers
- 2014 Canada's Best Diversity Employers
- 2013 New Canadians Employers
- 2013 Canada's Greenest Employers
- 2013 Top Employers for Young People

BILLING ACCURACY

Billing Accuracy is the percentage of invoices that are accurately calculated based on the customer's consumption and do not require adjustment or rebilling. This is a core expectation of customers. BC Hydro has therefore set targets to deliver consistently high performance. Billing accuracy is affected by items such as incorrect meter reads and various adjustments, such as correction to rate applied.

FIRST CALL RESOLUTION

First Call Resolution measures the percentage of calls that are resolved during the first contact with a call centre agent. This measure assesses customer service operations as a whole in terms of accurate and timely information flow, agent capability and quality, and a satisfying customer experience at a transaction level. BC Hydro utilizes a post call customer survey conducted by a leading North American call center industry research firm to measure First Call Resolution.

PROGRESSIVE ABORIGINAL RELATIONS DESIGNATION

The Progressive Aboriginal Relations certification that is conducted by an external auditor helps BC Hydro to assess whether it is achieving its 20 year goal of establishing relationships with First Nations built on mutual respect and that appropriately reflect the interests of First Nations. It does this by assessing the four key areas of Aboriginal employment, business development, capacity development and community engagement.

OUR PERFORMANCE

CUSTOMER SATISFACTION

Customer Satisfaction experienced slight downward pressure during fiscal 2014. After starting the year at 86 per cent, the 12-month rolling average satisfaction score dropped to 85 per cent in the middle of fiscal 2014. Our success in the areas of "ability to deliver reliable power" as well as the "continued commitment to customer service" helped us maintain our overall Customer Satisfaction score of 85 per cent achieving the plan target for the year.

PERFORMANCE MEASURES

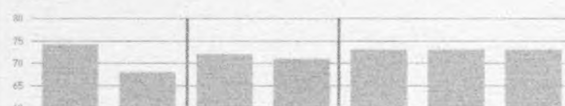
CSAT INDEX - CUSTOMER SATISFACTION INDEX (%)
(higher is better)

ACTUAL F2012	ACTUAL F2013	TARGET F2014	ACTUAL F2014	TARGET F2015[1]	TARGET F2016[1]	TARGET F2017[1]
87	86	85	85	85	85	85

BILLING ACCURACY (%)
(higher is better)

ACTUAL F2012	ACTUAL F2013	TARGET F2014	ACTUAL F2014	TARGET F2015[1]	TARGET F2016[1]	TARGET F2017[1]
98.4	98.5	98.4	99.1	99.0	99.1	99.2

FIRST CALL RESOLUTION (%)
(higher is better)



ACTUAL F2012	ACTUAL F2013	TARGET F2014	ACTUAL F2014	TARGET F2015[1]	TARGET F2016[1]	TARGET F2017[1]
74.2	68.0	72.0	71.0	73.0	73.0	73.0

PROGRESSIVE ABORIGINAL RELATIONS DESIGNATION

ACTUAL F2012	ACTUAL F2013	ACTUAL F2014	TARGET F2015[1], F2016[1], F2017[1]
SILVER	GOLD	GOLD	GOLD

[1] *Fiscal 2015 to fiscal 2017 performance targets as published in the BC Hydro 2014/15–2016/17 Service Plan.*

BILLING ACCURACY

This metric improved this fiscal year as an increased number of bills were generated through automated reads due to the installation of Smart Meters. Bills issued from automated reads improve billing accuracy and customer service by reducing the percentage of estimates required as well as lowering the number of bills requiring rework compared to bills that are issued from non-automated reads. At the end of the fiscal year, 94 per cent of customer bills were being issued using automated reads from smart meters. The billing accuracy results for fiscal 2014 were well above plan and targets for future years have been increased to reflect the expected continued benefit.

FIRST CALL RESOLUTION

First Call Resolution in fiscal 2014 improved from the previous year to end the year at one per cent below plan which is within the margin of error for the measurement survey and is therefore considered to be on target. Underlying drivers for repeat calls continue to be billing and payment related inquiries. In addition, the movement of less complicated calls to the self-serve environment continues to result in the call centre handling a greater percentage of complex calls that may not lend themselves to resolution on the first call.

PROGRESSIVE ABORIGINAL RELATIONS DESIGNATION

BC Hydro remains a gold-level certified company within the Canadian Council of Aboriginal Businesses Progressive Aboriginal Program. This certification confirms BC Hydro's commitment to demonstrating improvement in our company's Aboriginal relations business strategy.

Create a sustainable energy future in B.C. by carefully managing our impacts on the environment and fostering an energy conservation and efficiency culture.

STRATEGIES IN THE 2013/14 – 2015/16 SERVICE PLAN

- Continue to implement the Demand Side Management (DSM) plan, including Power Smart programs and conservation rate structures, supporting new energy efficiency regulations, and fostering an energy conservation and efficiency culture.
- Continue to meet the 93 per cent clean energy objective in the *Clean Energy Act* through purchasing energy from clean or renewable independent power producers and advancing clean energy capacity resources.
- Continue to meet regulatory requirements related to GHG emissions reporting and verification. Ensure that BC Hydro's buildings, vehicles and paper use are carbon neutral under the *B.C. Greenhouse Gas Reduction Targets Act*. Continue to facilitate the electrification of transportation in B.C.
- Manage the impact on the environment from BC Hydro's new developments and retrofits of existing facilities by incorporating an "avoid, minimize and offset" approach to project design, planning and implementation.
- Continue to implement environmental studies and projects related to water licence requirements under BC Hydro's Water Use Plans, to confirm the suitability of operational controls at hydroelectric generating plants.
- Continue implementing the PCB electrical equipment phase-out strategy, and pursue a long-term strategy for the handling, decontamination and disposal of PCB-contaminated equipment and materials.
- Ensure resources, training and tools are in place "on the ground" at BC Hydro's facilities and throughout our operations to identify risks and prevent environmental incidents; and, to deploy the best, most effective approaches to minimize impacts when incidents occur.
- Work in partnership with First Nations and communities to understand impacts related to managing BC Hydro's assets and implement compensation programs and other environmental projects reflective of this input.

FISCAL 2014 SUMMARY

BC Hydro seeks to avoid environmental impacts where possible and, then, where negative impacts cannot be avoided, we work to minimize and offset them in the long term.

CONSERVATION AND ENERGY EFFICIENCY

B.C.'s lowest cost resource option continues to be energy conservation and efficiency. By helping customers be more efficient and use their power wisely, BC Hydro can reduce the need for additional generation and help customers lower their bills. The *Clean Energy Act* also raises the bar for BC Hydro's reliance on demand-side measures. DSM is crucial for meeting the Act's requirement to meet 66 per cent of all new power demand through conservation by 2020.

OUR ENVIRONMENTAL FOOTPRINT

In addition, we are being proactive in ensuring the design, construction and integration of any new asset into our system meets our rigorous expectations around environmental performance. We seek to be transparent and to collaborate on solutions that reflect our values and

commitments. Where impacts require additional mitigation, we work with regulators, communities, stakeholders, and First Nations to ensure a balanced approach for long term ecosystem sustainment.

In fiscal 2014, the Fish and Wildlife Compensation Program (FWCP) was involved in numerous fish and wildlife enhancement projects that are delivered each year by dedicated proponents with FWCP funding. For example, the FWCP was involved in the planting of a brand new riparian forest and improving existing riparian habitat in two locations – at Colony Farm on the Coquitlam River in the Lower Mainland. The planting work was coordinated by Watershed Watch Salmon Society and the Kwikwetlem First Nation, with funding from the FWCP in the Coastal Region and will result in a much richer ecosystem that will benefit the four species of salmonids using these waters and the wildlife inhabiting the riparian zone.

In addition to the three programs spanning the Province, the Columbia Fish and Wildlife Program is partnering with Columbia Basin Trust to create and implement the East Kootenay Koocanusa Fish and Wildlife Program. The program, announced in spring 2013, is in response to long-standing public requests to address fish and wildlife issues in the Upper Kootenay River area, including the Koocanusa Reservoir from Canal Flats in the north to the border, and east to the Elk Valley. Koocanusa Reservoir is formed by Libby Dam on the Kootenay River in the United States.

We continue to implement the PCB phase-out program to meet the federal regulatory phase out requirement by 2025. In fiscal 2014, a risk audit was conducted by BC Hydro's internal audit group with the objective of assessing the current program's ability to meet regulatory requirements and determining a timeline for phase out. The audit results were positive with minor recommendations.

BC Hydro signed a 20-year agreement with Aevitas Inc. for PCB and hazardous waste management services. The service contract will ensure the safe management of processing PCB-contaminated wastes and the disposal of all hazardous wastes generated through the ongoing operation and maintenance of BC Hydro's electrical system.

BC Hydro has had an International Standards Organization (ISO)-consistent management system for environment since 1988. In fiscal 2014, we initiated a project to deliver an integrated safety, health and environment management system with the goal to reduce the frequency and severity of incidents and impacts to people, property, and the environment; to ensure due diligence in meeting compliance; and, to make the system easy to access and use in the field.

Environmental training has been provided to approximately 2,200 BC Hydro staff who are either directly doing work or managing work impacting the environment. Environmental training courses cover areas of common environmental risks across our operations including Spill Prevention and Response, PCB Awareness, Hazardous Waste Management, Heritage and Archaeology Awareness, Working in and Around Water, Soil Management and Disposal, and Wildlife Awareness.

WHAT WE MEASURE AND WHY

CONSERVATION

Demand Side Management is an important part of BC Hydro's plan to meet future supply needs. DSM savings can be measured either on an incremental or cumulative basis. BC Hydro's DSM performance is measured in its Service Plan as the cumulative rate of annual electricity savings (GWh/yr) resulting from DSM activities, including programs, codes and standards and rate structures and reflects savings that were initiated since fiscal 2008, following the 2007 BC Energy Plan. BC Hydro developed its annual cumulative DSM targets as part of long-term DSM and resource planning. BC Hydro's DSM plan compares well against other leading DSM jurisdictions in North America.

BC Hydro undertakes a comprehensive approach to estimating DSM energy savings. Depending on the DSM initiative, there can be up to four distinct areas of activity that ultimately contribute to the confirmation of DSM savings estimates: technical reviews of programs and energy conservation projects; site inspections on a sample of projects; measurement and verification of project performance; and evaluation of programs, conservation rates, building codes and product standards.

ELECTRICITY PRODUCTION GHG EMISSIONS

The Electricity Production GHG Emissions measure quantifies the direct GHG emissions associated with electricity generation, from BC Hydro-owned generating stations and from our IPPs in B.C., and the fugitive, or leaking sulphur hexafluoride (SF_6)[1] releases from our transmission and distribution system. Electricity Production GHG Emissions are reported by calendar year rather than fiscal year to ensure consistency with GHG emissions reports filed under the *Canadian Environmental Protection Act*, 1999 and the B.C. Reporting Regulation.

The Electricity Production GHG Emissions targets are based on the forecasted need to run the generating stations, taking into account hydrology, reliability, system needs and market conditions, including the expected price of carbon emissions. GHG emissions from BC Hydro-owned generating stations and fugitive SF_6 releases are calculated using methods required under the B.C. Reporting Regulation.

The reported emissions are subject to mandatory third-party verification by an accredited verifier. GHG emissions from IPPs are estimated based on information supplied by the IPPs.

CARBON NEUTRAL PROGRAM EMISSIONS

BC Hydro became carbon neutral in our operations in 2010, along with the entire B.C. public sector. This means that we measure the GHG emissions from our vehicle fleet, buildings (energy used for heating, cooling, lighting, and IT equipment) and paper use, in accordance with the Province's guidelines for public sector organizations. We also implement measures to reduce those emissions and report on these reduction measures in our annual Carbon Neutral Action Report, which is published at http://www.bchydro.com/about/sustainability/climate_action/greenhouse_gases.html.

Finally, we offset any remaining emissions from these sources through investments in offsets from the Ministry of Environment.

Carbon Neutral Program Emissions are reported by calendar year rather than fiscal year to ensure consistency with GHG emissions reports filed under the B.C. Carbon Neutral Government Regulation. The Carbon Neutral Program Emissions targets are based on a forecast of emissions, taking into account emission reduction initiatives that are planned or underway. Carbon Neutral Program emissions are calculated using the Province's SMARTTool, based on BC Hydro's reported fuel, electricity and paper use. Small sources of emissions such as boats, snowmobiles and all-terrain vehicles, estimated to comprise one per cent or less of total Carbon Neutral Program Emissions, are excluded from reporting in accordance with provincial guidelines. All public sector organizations are required to certify and confirm the accuracy and completeness of the data submitted into SMARTTool by completing self-certification. In addition, a representative sample of public sector organizations is selected for independent verification of their GHG emissions reporting procedures.

CLEAN ENERGY

The Clean Energy target aligns with the objectives set forth in the 2010 *Clean Energy Act*. The Clean Energy measure represents a minimum threshold generation target in accordance with the B.C. Government's requirement that at least 93 per cent of electricity generation in the province be

[1] *Sulfur Hexafluoride (SF_6) is a chemical used in electrical equipment to provide insulation.*

from clean or renewable resources—i.e., from biogas, biomass, energy recovery generation, geothermal, hydro, solar, tidal, wave, wind or other potential clean or renewable electricity sources recognized by the B.C. Government.

Consistent with B.C. regulation, this measure does not include electricity to serve demand from facilities that liquefy natural gas for export by ship. BC Hydro does not compare its results for this performance measure against other utilities. The measure uses actual historical generation data obtained from BC Hydro and IPPs. The generation data is reviewed and verified internally at BC Hydro for reliability, consistency and data integrity.

OUR PERFORMANCE

DEMAND SIDE MANAGEMENT

For fiscal 2014, BC Hydro's cumulative energy savings of 4,776 GWh/yr were below the Service Plan target of 5,100 GWh/yr, largely due to an unplanned adjustment to prior year savings resulting from an evaluation of the Residential Inclining Block conservation rate. The evaluation revealed that the conservation rate did achieve its overall objective of encouraging conservation, but at a smaller magnitude than planned.

This past fiscal year was an important year for DSM as BC Hydro made a number of adjustments to DSM initiatives consistent with the Integrated Resource Plan action to moderate current DSM spending while maintaining the long term savings target. Although BC Hydro's energy savings results were below plan, significant savings were achieved with BC Hydro's residential, commercial and industrial customers allowing BC residents and businesses to save energy and reduce their electricity bills.

PERFORMANCE MEASURES

DEMAND-SIDE MANAGEMENT (GWh/yr)

Cumulative annual electricity savings since 2008 *(higher is better)*

ACTUAL F2012	ACTUAL F2013	TARGET F2014	ACTUAL F2014	TARGET F2015[2]	TARGET F2016[2]	TARGET F2017[2]
3,424	4,460	5,100[1]	4,776	5,500	6,300	6,700

[1] *This is a cumulative target of energy savings since fiscal 2008. Target in 2013/14-2015/16 Service Plan was 5,100 GWh/yr. The fiscal 2014 target was revised to 5,000 in the current Service Plan (2014/15 to 2016/17) in order to align with the 2013 Integrated Resource Plan.*

[2] *Fiscal 2015 to fiscal 2017 performance targets as published in the BC Hydro 2014/15–2016/17 Service Plan.*

ELECTRICITY PRODUCTION GREENHOUSE GAS (GHG)

The Electricity Production GHG Emissions measure includes emissions from electricity generation, electricity purchased from B.C. IPPs, and fugitive SF_6 releases. The calendar year 2013 Electricity Production GHG emissions were 730 kilotonnes CO_2e, which is three per cent above the plan of 710 kilotonnes CO_2e. Burrard Generating Station and the Island Co-Generation IPP were both called upon to run for Mica outage support and to meet peak loads during a period of cold weather in December. In addition, the Island Co-Generation IPP was required to run for Vancouver Island reliability in December. Fugitive SF_6 releases and emissions from biomass IPPs were both higher than originally forecasted.

When compared to other Canadian hydroelectric utilities, BC Hydro's 2013 Electricity Production GHG Emissions of 730 kilotonnes CO_2e were higher than Manitoba Hydro's reported 2012 total emissions of 146 kilotonnes CO_2e and Hydro-Québec's reported 2013 emissions of 290 kilotonnes CO_2e from thermal power plants and equipment containing CF_4 and SF_6.[1,2] Our performance relative to Manitoba Hydro and Hydro-Québec reflects the higher proportions of hydroelectric generation in the resource mix for those utilities. The GHG intensity of electricity generated by

[1] *Tetrafluoromethane (CF_4) and sulfur hexafluoride (SF_6) are chemicals used in electrical equipment to provide insulation.*

[2] *BC Hydro supplies roughly twice the amount of electricity as Manitoba Hydro and about one quarter of the electricity supplied by Hydro-Québec.*

BC Hydro and our IPPs in B.C. has ranged from 9 to 28 tonnes per GWh between 2008 and 2012, which is significantly lower than the average electricity generation intensity of 160 to 200 tonnes per GWh for Canadian provinces and territories, many of which do not have a resource mix so favourable towards hydroelectricity.

CARBON NEUTRAL PROGRAM EMISSIONS

The Carbon Neutral Program Emissions measure includes emissions from BC Hydro's vehicle fleet, buildings and paper use. The calendar year 2013 Carbon Neutral Program Emissions were 27.0 kilotonnes CO_2e, which is ten per cent below the target of 30 kilotonnes CO_2e. The Carbon Neutral Program Emissions were six per cent lower in 2013 than in the previous calendar year. Half of this reduction is attributable to changes in emission factors prescribed by the B.C. government to calculate the emissions. The other half of this reduction is primarily the result of reduced natural gas use in some buildings and a one per cent reduction in fuel use by the vehicle fleet.

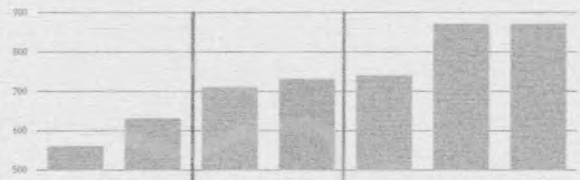
Due to the distinctive nature of our operations, it is difficult to compare BC Hydro's Carbon Neutral Program Emissions to those of other public sector organizations. BC Hydro is unique in that we require a relatively large vehicle fleet to support our province-wide operations. From 2010 to 2012, BC Hydro reported the eighth highest annual emissions among the public sector organizations (2013 results are not yet available for benchmarking).

CLEAN ENERGY

For fiscal 2014, Clean Energy generation was higher than plan due to increased large hydro generation.

PERFORMANCE MEASURES

ELECTRICITY PRODUCTION GHG EMISSIONS[1] (kt)
Carbon dioxide equivalent metric kilotonnes from electricity production *(lower is better)*



ACTUAL C2011	ACTUAL C2012	TARGET C2013	ACTUAL C2013	TARGET C2014[2]	TARGET C2015[2]	TARGET C2016[2]
560	631	710	730	740	870	870

CARBON NEUTRAL PROGRAM EMISSIONS (kt)
Carbon dioxide equivalent metric kilotonnes from building energy use and vehicles *(lower is better)*

ACTUAL C2011	ACTUAL C2012	TARGET C2013	ACTUAL C2013	TARGET C2014[2]	TARGET C2015[2]	TARGET C2016[2]
30.0	28.8	30.0	27.0	29.0	29.0	29.0

CLEAN ENERGY (%)
Energy from clean or renewable resources
(higher is better)

ACTUAL F2012	ACTUAL F2013	TARGET F2014	ACTUAL F2014	TARGET F2015[2]	TARGET F2016[2]	TARGET F2017[2]
98.1	98.2	93.0	97.1	93.0	93.0	93.0

[1] *BC Hydro is reporting its GHG emissions by calendar year instead of fiscal year to align with GHG emissions reports filed under the Canadian Environmental Protection Act, 1999, the B.C. Reporting Regulation and the B.C. Carbon Neutral Reporting Regulation.*

[2] *Fiscal 2015 to fiscal 2017 performance targets as published in the BC Hydro 2014/15–2016/17 Service Plan. The Electricity Production GHG Emissions targets are based on the forecasted need to run the generating stations, taking into account hydrology, reliability, system needs and market conditions, including the expected price of carbon emissions. The targets for Electricity Production GHG Emissions have been recalibrated from the 2013/14–2015/16 Service Plan to reflect updates to the forecast. The upward revision of the plan compared to the previous Service Plan is primarily related to a forecasted increase in market electricity prices relative to the price of natural gas, as well as new IPPs expected to come online.*

Foster economic development opportunities across B.C. through our projects, practices and advancement of the energy efficiency and clean energy sectors.

STRATEGIES IN THE 2013/14 – 2015/16 SERVICE PLAN

- Integrate economic development principles into decision-making tools, procurement practices, business cases and corporate policies.
- Ensure appropriate tariff/rate structures are in place to enable the expansion of business activity across B.C.
- Develop new business models to enable new energy projects that make sense from a long-term, provincial perspective while minimizing customer impacts.
- Help expand and retain current customers by fostering business competition through Power Smart programs and the delivery of clean, reliable energy.

FISCAL 2014 SUMMARY

BC Hydro contributes to economic development through our provision of clean: reliable power; competitive rates; and our role in attracting, expanding and retaining domestic and trade customers. BC Hydro has also helped to make businesses and industry more competitive through our Power Smart programs, supported First Nations economic development across B.C., and purchased competitively priced energy from independent power producers.

In fiscal 2014, BC Hydro conducted numerous technical studies and worked towards commercial agreements to supply electricity to and interconnect several LNG customers. In the upstream natural gas sector, BC Hydro is currently constructing new transmission (the Dawson Creek/Chetwynd Area Transmission Project) to supply the needs of natural gas producers in the region, and is in the planning stages for a second transmission project into the area. In mining, BC Hydro commenced electricity supply to the new Mount Milligan mine in fiscal 2014, and entered into contracts with Imperial Metals to support the extension of the transmission system to serve the Red Chris mine which will be operational in the summer of 2014.

WHAT WE MEASURE AND WHY

CAPITAL SPENDING IN BRITISH COLUMBIA

The BC Hydro Capital Spending in British Columbia measure was introduced in the fiscal 2012/13–2014/15 Service Plan to serve as a measure of BC Hydro's contribution to economic development in B.C. The measure is calculated as total capital spend per BC Hydro's financial system adjusted to exclude estimates of major capital purchases from outside B.C, as these expenditures do not directly contribute to economic activity in B.C.

This measure is more of an indicator of economic development in BC than a true target that we are taking action to meet. After review, BC Hydro has decided to measure its contribution to economic development through reliability, maintaining competitive rates, and through implementing our capital plans. Starting with the fiscal 2014/15–2016/17 Service Plan, these measures will provide a more accurate reflection of how BC Hydro contributes to B.C. communities and economic development.

OUR PERFORMANCE

BC Hydro continues to invest significantly to refurbish its aging infrastructure and build new assets for future growth. We are forecasting capital expenditures of approximately $6 billion over the next three years. Capital expenditures for the twelve months ended March 31, 2014 were $2,036 million, with $1,968 million calculated to be BC Hydro's Capital Spend within B.C., which was slightly higher than our total capital plan of $1,950 million and our Capital Spend within B.C. target of $1,886 million, net of government contributions.

PERFORMANCE MEASURES

BC HYDRO CAPITAL SPEND ($ millions within B.C.)

ACTUAL F2012	ACTUAL F2013	TARGET F2014[1]	ACTUAL F2014	TARGET F2015[2]	TARGET F2016[2]	TARGET F2017[2]
1,853	1,865	1,963	1,968	NR	NR	NR

[1] *The 2013/14 Service Plan target was $1,963. The fiscal 2014 target was updated in the 2014/15 Service Plan to $1,886 to net government contributions to more accurately compare to the reporting of actuals. The target is based on total forecast BC Hydro capital expenditures adjusted to exclude estimates of major capital purchases from outside of B.C. Actual expenditures are net of government contributions for the Northwest Transmission Line project.*

[2] *After review, BC Hydro has decided to measure its contribution to economic development through reliability, maintaining competitive rates, and through implementing our capital plans.*

Deliver value for British Columbia and maintain competitive rates by efficiently and responsibly managing our business.

STRATEGIES IN THE 2013/14 – 2015/16 SERVICE PLAN

- Implement recommendations from the Government Review report to realize cost-savings and efficiencies and continue to focus on management and control of our cost structure.
- Develop a 10-year capital plan and effectively deliver on BC Hydro's capital investment program, including process and procurement improvements.
- Implement people, process and technology to improve operational excellence, safety and reliability of the Transmission & Distribution (T&D) organization through the Transformation Initiative. This initiative includes improving work delivery methods, resourcing strategies, integrated T&D planning, as well as technology platforms.
- Realize value through innovative procurement strategies, strategic sourcing and by building strong supplier relationships.
- Manage the cost of energy by: implementing a 20-year Demand-Side Management plan; procuring and/or building new electricity supply at competitive costs; making prudent short-term generate and buy decisions; and, optimizing BC Hydro's ability to use the flexibility of our heritage assets.
- Optimize BC Hydro's balance sheet and cost of capital.

FISCAL 2014 SUMMARY

PLANNING TO MEET FUTURE DEMAND

As BC Hydro moves forward with significant investments to B.C.'s electricity system, we will spend an average of $2 billion a year (not including any construction costs related to Site C) for the next three years on capital projects. While making these investments, BC Hydro recognizes that there is an impact on rates and we will carefully manage costs, operate in an efficient and cost-effective manner, and strive to ensure that projects deliver benefits and are on time, and within both scope and budget.

KEEPING RATES COMPETITIVE

We achieved our target of $391 million in operating cost savings in the three-year period between fiscal 2012 and fiscal 2014, as we committed to in our response to the recommendations following the 2011 Government Review of BC Hydro. We also met our headcount equivalent target through attrition and proactive management of headcount levels throughout the year.

In November 2013, the Province announced a 10 year plan detailing how the Province and BC Hydro will keep electricity rates as low as possible while BC Hydro makes investments in aging assets and new infrastructure to support British Columbia's growing population and economy. As part of the 10 year plan, BC Hydro is implementing a number of measures to keep rates low, including prioritizing capital and Power Smart spending, employee reductions, surplus property sales, management of operating costs, and planned closure of Burrard Thermal Generating Station. New measures in the plan will also reduce the amount of money that the Province receives from BC Hydro and free up additional cash to support investments in infrastructure.

IMPROVING OUR SUPPLY CHAIN

During fiscal 2014, materials management, fleet services and procurement were consolidated under a single Supply Chain function. This integration is part of a broader strategy developed to better meet BC Hydro's Supply Chain business requirements and to identify productivity and efficiency opportunities through changes in people, process and technology.

CONTINUOUS IMPROVEMENT AND TRANSFORMATION

A broad people, process and technology change initiative in our T&D group has been underway and focused on driving efficiencies in how work is performed, from planning through execution. Most of the initiatives contemplated are now complete or adequately embedded within the business, and are driving the expected benefits. In fiscal 2014, key deliverables from this program included the introduction of regional schedulers in T&D to drive better alignment of field worker capacity and workload for distribution work at a headquarter level, and the consolidation of T&D's express connection service centers from seven to three to reduce costs and provide a more consistent customer experience.

WHAT WE MEASURE AND WHY

COMPETITIVE RATES

BC Hydro's electricity rates are among the most competitive in North America, in large part due to the past investments in infrastructure that help us generate and deliver cost effective, clean energy. Our competitive rates measure compares BC Hydro's rates against other utilities across North America for three types of power classes: a typical residential customer with an estimated monthly consumption of 1,000 kWh; a medium customer with an estimated monthly consumption of 400,000 kWh; and, a large customer with an estimated monthly consumption of 30,600 MWh.

Pursuant to Rate Comparison Regulation under the *Clean Energy Act*, issued on June 28, 2011, BC Hydro provides an Electricity Rate Comparison Annual Report to the Minister of Energy and Mines and to the BCUC. This is based on survey information taken from the Hydro Québec report, Comparison of Electricity Prices in Major North American Cities, which compiles monthly bill and average prices for 12 Canadian utilities and 10 U.S. utilities.

NET INCOME

BC Hydro bases net income targets on the latest financial forecast. The targets are based on BC Hydro's allowed return on equity and reflect expected rate increases required to enable BC Hydro to cover its costs. BC Hydro ensures the integrity of its financial data by maintaining robust systems of financial internal controls. The financial statements are also audited annually by an independent external accounting firm.

OPERATING COSTS

Operating costs are defined as personnel, materials and external services expenses included in income, that are incurred in the day-to-day operation of BC Hydro's electric utility, net of recoveries, capitalized costs and reclassification adjustment. Operating costs are impacted by such things as the age of assets and maintenance requirements, inflation and other cost increases for materials and supplies, growth in the customer base, and changes in environmental and regulatory standards.

DEBT TO EQUITY

Debt to Equity is defined as the ratio of debt to the sum of the total of debt and equity. This is of particular interest to sector analysts, rating agencies, and finance providers. It is commonly used in the financial community. It measures the leverage in the company and is used in the regulation of electricity companies in some jurisdictions.

OUR PERFORMANCE

COMPETITIVE RATES

Based on the 2013 Hydro Québec Study "Comparison of Electricity Prices in North American Cities," which was issued in August, BC Hydro achieved a 1st Quartile rating as targeted. The study also found BC Hydro to have the 3rd lowest rates overall for residential customers among the 22 North American utilities surveyed, 4th lowest for medium power and 5th lowest for the large power categories. It is in large part due to the development of our large generating facilities built between the 1950s and 1980s that our rates are so competitive. We also work hard to carefully manage our costs and operate in an efficient and cost effective manner.

NET INCOME

Consolidated net income for fiscal 2014 was $549 million, $4 million higher than planned net income of $545 million, which is slightly above target.

OPERATING COSTS

BC Hydro is focused on meeting its operating costs targets which continues to be a challenge due to required maintenance on aging infrastructure, operation and maintenance of new assets, an increase in the number of customers we serve, and the increasing costs of fuel and materials. Operating costs for fiscal 2014 were $702 million, $3 million higher than plan of $699 million. This is less than 0.5 per cent over plan and considered to be on target.

DEBT TO EQUITY

The debt to equity ratio of 80:20 is on target. BC Hydro's payment to the province is equal to 85 per cent of BC Hydro's net income if the debt to equity ratio, after deducting the payment, is not greater than 80:20. Based on fiscal 2014 results, the dividend to be paid to the province is $167 million, which is 30 per cent of net income. This was below the 85 per cent payment due to the 80:20 debt to equity ratio cap.

More information on debt to equity is available in the Financial Statements.

As part of the 10 year plan, the Province will restrict the amount of dividends received from BC Hydro starting in fiscal 2018 until such time as the debt to equity ratio reaches 60:40. BC Hydro does not anticipate reaching the debt to equity ratio of 60:40 during the 10 year period. As a result of this change, the debt to equity ratio will be removed as a performance measure effective fiscal 2015.

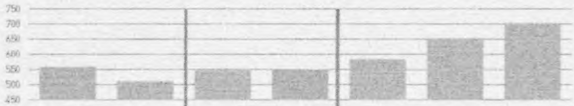
PERFORMANCE MEASURES

COMPETITIVE RATES

1st Quartile

- ACTUAL F2012, F2013, F2014
- TARGET F2015[1], F2016[1], F2017[1]

NET INCOME *($ millions)*



ACTUAL F2012	ACTUAL F2013	TARGET F2014	ACTUAL F2014	TARGET F2015[1]	TARGET F2016[1]	TARGET F2017[1]
558	509	545	549	582	652	701

OPERATING COSTS[2] *($ millions)*

ACTUAL F2012	ACTUAL F2013	TARGET F2014	ACTUAL F2014	TARGET F2015[1]	TARGET F2016[1]	TARGET F2017[1]
665	705	699	702	706	713	730

DEBT TO EQUITY [%][3]

80:20

ACTUAL F2012, F2013, F2014

[1] *Fiscal 2015 to fiscal 2017 performance targets as published in the BC Hydro 2014/15–2016/17 Service Plan.*

[2] *The 2014/15 Service Plan defines operating costs (or "domestic base operating costs") as personnel, materials and external services expenses included in income, that are incurred in the day to day operation of BC Hydro's electric utility, net of recoveries, capitalized costs and reclassification adjustment. The domestic base operating costs exclude: Powerex and Powertech operating costs, operating costs related to energy purchase agreements accounted for as capital leases, and the transitioning of IFRS-ineligible capital overhead into operating costs over a 10-year period.*

[3] *As part of the 10 year plan, the Province will restrict the amount of dividends received from BC Hydro starting in fiscal 2018 until such time as the debt to equity ratio reaches 60:40. BC Hydro does not anticipate reaching the debt to equity ratio of 60:40 during the 10 year period. As a result of this change, the debt to equity ratio will be removed as a performance measure effective fiscal 2015.*

Empower a team that is committed to safety, innovative and prepared for the future.

STRATEGIES IN THE 2013/14 – 2015/16 SERVICE PLAN

- Create strategies to address workforce gaps and development plans to ensure a readily available talent pool for critical roles.
- Continue to prudently manage: staffing levels; ensure the optimal complement of new recruits, skilled, experienced and high-performing employees; and, leverage contracted and outsourced service providers in an efficient manner.
- Provide a sustainable total compensation offer that serves to attract the best possible candidates, align employees to our key objectives, retain top performers, and enhance employees' well-being.
- Support leaders to engage employees so they are innovative and highly motivated to work together safely and effectively.

FISCAL 2014 SUMMARY

BC Hydro requires highly qualified technical, trade and degreed professionals to meet its operational goals and objectives. In the future, BC Hydro's demand for people with industry-specific expertise and specialized skills will continue as it undertakes large-scale capital projects. Burgeoning demand in labour markets in Western Canada and the retirement of aging workers within B.C.'s workforce are creating higher demand for people across the region which, in turn, can impact attrition rates within BC Hydro.

To address this need for a highly qualified, diverse and flexible workforce, BC Hydro has established programs to close the gap between our need for workers and the supply. BC Hydro opened a new Trades Training Centre this year which enhanced our ability to deliver specialized technical and safety training in a simulated environment. The Trades Training Center is the primary venue for formal apprenticeship and journey person training across all trades. Safety and technical training and safety leadership continue to be emphasized to ensure that our employees and managers are skilled to deliver work safely in our high-hazard industry.

Vacancy management is a key strategy for managing staffing as employees leave the company or change jobs. BC Hydro manages headcount and staffing levels at or below the budgeted labour plan, and applies company-wide standards to filling vacant positions. In addition, BC Hydro monitors monthly attrition and recruitment levels, coordinates company-wide resource management for large scale projects, and manages the impacts related to the annual hiring of apprentices and trainees.

WHAT WE MEASURE AND WHY

EMPLOYEE SUSTAINABLE ENGAGEMENT SCORE

The Employee Sustainable Engagement Score is BC Hydro's annual measure of employee engagement through an all-employee survey. The sustainable engagement score indicates the level to which employees connect with the organization, whether or not they feel the company provides the tools and resources to work effectively, and whether or not they feel that the company cares about their personal well-being.

BC Hydro's results are benchmarked against a number of Towers Watson indicators, including their Global Utilities Norm and their Canada National Norm. Our annual target is to meet or exceed the Towers Watson Global Utilities norm for sustainable engagement. This target is adjusted annually to benchmark against shifts in the norms within the utilities industry.

PERFORMANCE MEASURE

EMPLOYEE SUSTAINABLE ENGAGEMENT SCORE[1]
(% favourable)

78 ACTUAL F2013	79 TARGET F2014	MEET OR EXCEED TOWERS WATSON GLOBAL UTILITIES INDEX (GUI) SCORE
	79 ACTUAL F2014	(F2014 GUI SCORE = 79)
		TARGET F2015, F2016, F2017

[1] *The target for each of fiscal 2015, fiscal 2016, and fiscal 2017 is to meet/exceed the benchmark of the Towers Watson Global Utilities norm for that year.*

OUR PERFORMANCE

EMPLOYEE ENGAGEMENT

The 2013 enterprise employee survey revealed improvement in both response rate and in engagement results across all affiliations.

The response rate was 72 per cent which is a three per cent increase over 2012; and the Sustainable Engagement score was per cent which is a one per cent increase over the 2012 results. This outcome met our objective to meet/exceed the benchmark of the Towers Watson Global Utilities norm of 79 per cent in 2013.

The survey is an annual measure, and is deployed in September. Follow up actions are focused on continuous improvement measures that most impact employees. In 2013, these were organizational continuity, work clarity and prioritization and the continued impacts of increased financial constraints on career opportunities and development.

Based on the 2013 survey results and employee comments, the company has identified two areas for action in the coming year: Leadership and integrity, and career development. Leadership and integrity involves communicating a clear vision for the future and continuing to improve the dialogue about objectives and decisions between senior leaders, managers and employees. Career development involves leveraging internal recruitment and training opportunities to support employees in developing their careers at BC Hydro.

RISK AND CAPACITY

BC Hydro is exposed to numerous risks, which can be broadly classified as either "Operating" or "Strategic". Operating risks arise from the construction, ownership, operation and decommissioning of the Company's assets. Significant strategic risks include both long-term and short-term load/resource balance, exposure to commodity and financial market prices, stakeholder relationships, and access to adequate funding at a reasonable cost. The consequences of these risks can include safety, environmental, financial, reliability and reputational impacts and can range in scale from minor to catastrophic. Risks that primarily impact financial performance are discussed in the Management's Discussion and Analysis. Risks that primarily impact organizational performance are discussed in this section with additional mitigating strategies outlined in the Report on Performance.

BC Hydro strives to manage all the risks it faces on a cost effective basis, taking into account the potential benefits to be gained in return for acceptance of the risk (that is, balancing risk and opportunity). BC Hydro also takes into account the provisions of externally recognized standards appropriate to the risk being managed.

Risk Management does not imply the elimination, or even the mitigation, of all risks. Rather, it necessarily includes not only trade-offs between competing objectives, including the cost of risk reduction, but also consideration of the reward that justifies the acceptance of risk. Risks that could have significantly impacted BC Hydro meeting its objectives in fiscal 2014 included:

SAFELY KEEP THE LIGHTS ON

RISK: BC HYDRO OPERATIONS MAY EXPOSE PEOPLE TO UNSAFE CONDITIONS.

The generation, transmission and distribution of electricity inherently results in certain safety risks to BC Hydro's employees, contractors, and the public. To manage employee, contractor and public safety, BC Hydro endeavours to be compliant with occupational safety and health regulations, education and training to support awareness and culture, safe asset design, barrier installation, safe work procedures, safety practice regulations and communications. Emergency response plans are also prepared to limit injury and loss to life and to restore electric service on a timely basis.

BC Hydro is implementing the recommendations of our Safety Taskforce in order to permanently transform BC Hydro's safety culture and supporting safety processes. In addition to systematically identifying and, where possible, reducing the number of hazards through work-planning activities, work procedure development and Safety by Design, BC Hydro is also working with educators and curriculum specialists to develop high-quality, engaging and relevant resources that provide valuable information on electrical safety for those who may inadvertently come into contact with our system. Maintaining our recreation areas with signage outlining simple safety rules and procedures while swimming, boating, camping or hiking near our facilities help to raise awareness of hazards at our facilities and keep the public safe.

RISK: SEVERE WEATHER MAY IMPACT BC HYDRO'S SYSTEM AND LOAD.

Severe weather, such as winter storms, can cause significant damage to our transmission and distribution lines resulting in widespread system outages and significant repair costs. In addition, cold weather is a significant driver of residential load, with colder years resulting in higher demand for electrical heating. Through prudent system planning, vegetation management, and storm response preparation, BC Hydro has developed a robust system to withstand many weather events, and when necessary, has the flexibility to recover effectively when customers are impacted.

In fiscal 2014, BC Hydro experienced 10 major weather related events each causing more than 70,000 customer-hours of interruption. To prepare for these types of potential weather events, beginning as far out as 5 days before, our meteorologists provide updates to our operational managers specific to the significance of the emerging weather event. As the storms approach, updates become more frequent and precise to provide the operational managers an opportunity to mobilize crews to ensure we have adequate resources available in the right geographic locations. By having resources available, frequency and duration of outages can be minimized. For example, two major

windstorms occurred in February 2014 on Vancouver Island and in the Lower Mainland and impacted more than 250,000 customers; however, due to advance preparations and the effective management of available resources, all customers had their service restored in an effective priority sequence.

RISK: ASSET FAILURE.

Significant risks to the reliability of BC Hydro's system include aging infrastructure and natural disasters such as earthquakes or flooding. Long-term investment planning, asset maintenance and replacement programs, insurance contracts, emergency response programs, and a diverse supply of energy options all serve to reduce the risk of asset failure. This includes monitoring infrastructure and comparing against national and international best practices. Interim risk management plans and capital upgrade programs are initiated to improve dam safety such as current programs including the Ruskin Dam right abutment and spillway work, the Spillway Gate Reliability Program and the Bennett Dam Spillway chute resurfacing.

Prudent system design plans for redundancy to mitigate risk when an asset fails. For example, a significant asset failure occurred in fiscal 2014 at the 66-year-old Murrin Substation in Vancouver when a large transformer failed. Due to effective system planning, the electrical supply for about one-third of BC Hydro's downtown Vancouver customers was able to be transferred to another transformer at the substation. Until a new transformer was brought in to replace the failed transformer, the risk of a significant reliability incident was higher than normal. However, BC Hydro also had contingency plans in place to provide supply if the remaining transformer was impacted.

A second significant asset failure occurred when a generator at the G.M. Shrum Generating Station (GMS) failed in mid-November. This resulted in a 300 MW unit being out of service for six weeks. This event occurred during a time of year when BC Hydro relies on generators being in-service at GMS. BC Hydro had contingency plans that enabled generation to be supplied from other parts of the province by curtailing other planned maintenance outages. The generator was repaired and returned to service by local crews.

RISK: BC HYDRO'S INFORMATION TECHNOLOGY SYSTEMS MAY BE INFILTRATED BY MALICIOUS SOFTWARE.

BC Hydro, as part of the overall electrical utility business in North America, is a potential target for cyber-attack.

With an increasing reliance on technology to manage data about our customers and employees and accessing our critical operating systems, BC Hydro, as are other North American utilities, is increasing its capabilities in electronic security and processes.

BC Hydro manages its electronic security in a very comprehensive way. Our systems are secured through proactive measures to reduce the risk before a malicious event occurs but we also have systems and techniques to detect and minimize impacts on the business should a threat occur.

SUCCEED THROUGH RELATIONSHIPS

RISK: BC HYDRO MAY BE UNABLE TO PROACTIVELY RESPOND TO FIRST NATIONS PRIORITIES ON A TIMELY BASIS.

First Nation traditional territories encompass the entire land mass of British Columbia. All of BC Hydro's power generation facilities, transmission and distribution infrastructure are situated on First Nation's traditional territories, reserve and/or treaty settlement lands.

Aboriginal people hold a distinct historical, legal and cultural status within Canada and represent Canada's fastest growing population. Aboriginal peoples' rights are protected within the Constitution of Canada. Numerous court decisions have clarified and further defined these rights, as well as the obligations of the Crown in relation to them. Treaties set out the Aboriginal rights of a particular First Nation. In British Columbia there are a few modern day and historic treaties; however, for the majority of the 203 First Nations, treaties are not in place.

BC Hydro must uphold the Honour of the Crown in all of its dealings with First Nations. The absence of treaties does not alleviate BC Hydro's responsibility to fully understand the impact of its activities on Aboriginal rights, its responsibility to mitigate, and, where appropriate, accommodate. In fiscal 2014, BC Hydro signed two impact benefits agreements with First Nations associated to our capital build program.

To ensure that BC Hydro understands where its proposed activities may impact Aboriginal rights, we undertake consultation with the potentially affected First Nations. Evidence of consultation is also required to obtain a variety of permits and regulatory approvals we need to undertake our activities. At BC Hydro, we actively build relationships with First Nations and, more broadly, with Aboriginal people, helping us to increase Aboriginal participation in our business.

RISK: PLANNED RATE INCREASES MAY IMPACT CUSTOMERS.

While B.C. is expected to remain one of the lowest cost electricity jurisdictions in North America, rate increases are projected to be above inflation for several years. These continued increases may put financial pressure on customers. BC Hydro has Power Smart programs in place to mitigate the effects of rate increases and online tools help customers to manage their energy use safely and efficiently.

BC Hydro continues to communicate its long-term plan for meeting B.C.'s demand for energy through the IRP and through communication about our capital projects. We work to build public understanding of our infrastructure programs and conservation and energy efficiency initiatives.

In fiscal 2014, Government announced a 10 year plan to keep rates low for customers while also recognizing that infrastructure needs to be updated. The IRP was approved and shared publicly. We continue to look for ways to operate more efficiently. This includes keeping operating cost increases to less than the rate of inflation over the next two fiscal years and to prepare now for rate increase caps set out in the 10 year plan for fiscal 2017, fiscal 2018 and fiscal 2019.

MIND OUR FOOTPRINT

RISK: BC HYDRO'S DEMAND SIDE MANAGEMENT EFFORTS MAY NOT DELIVER THE DESIRED LEVEL OF SAVINGS.

Demand Side Management remains the most cost effective supply option available to meet the growing demand for energy. However, long term customer responses to rate structures and DSM programs are difficult to predict and can vary from estimated values in both timing and amount. BC Hydro must balance the benefits of DSM against the risk of having insufficient supply should the targeted DSM savings not be realized. Less conservation means higher load growth, ultimately requiring construction of more assets by BC Hydro or others.

BC Hydro regularly monitors the response to DSM initiatives and makes adjustments to either the initiatives or the planned level of energy savings. We also monitor cumulative savings to ensure we are on track to meet our DSM goals. The risks associated with reliance on a particular level of DSM are subject to rigorous analysis in connection with the preparation of the IRP. BC Hydro adjusts advertising levels and incentive offers to help increase or decrease participation rates and the resulting energy savings.

ENGAGE A SAFE AND EMPOWERED TEAM

RISK: BC HYDRO MAY NOT BE ABLE TO MAINTAIN THE NECESSARY SKILLSETS TO EXECUTE ON ITS OBJECTIVES.

BC Hydro's core work requires skillsets and qualifications that are in high demand within the Canadian labour market. While attrition rates at BC Hydro continue to be low, replacing skilled employees who retire or resign can be difficult and lengthy. A lack of qualified technical, trade and degreed professionals could impact BC Hydro's ability to fulfill its work plans, BC Hydro has mitigated its risks by focusing recruiting efforts on hiring new-career entrants, where there are considerably more workers available. Using our Trades Training Centre, BC Hydro places these newly-hired employees into trainee and apprentice programs, and trains them to BC Hydro's requirements over the course of two to four years. BC Hydro assesses the potential gaps between long-term labour demand and supply, and then sets the hiring volumes for trainee and apprentice programs so that new graduates will close the gaps projected by the plan. This long-term strategy is providing a steady stream of qualified technical trades and professionals to fill BC Hydro's most critical roles.

In addition to our trainee and apprentice programs, BC Hydro also focuses attention on our highest priority roles: Engineers, Communication, Protection and Control Technologists, Power Line Technicians, Cable Splicers, Electricians, and Field Managers. We track vacancy rates, attrition rates, demographics and exit projections, and have project plans aimed at improving attraction, retention and employee engagement within these roles. In fiscal 2014, this role-focused approach enabled BC Hydro to fill external vacancies across all of its high-priority roles, with significant progress made for Power Line Technicians and Engineers.

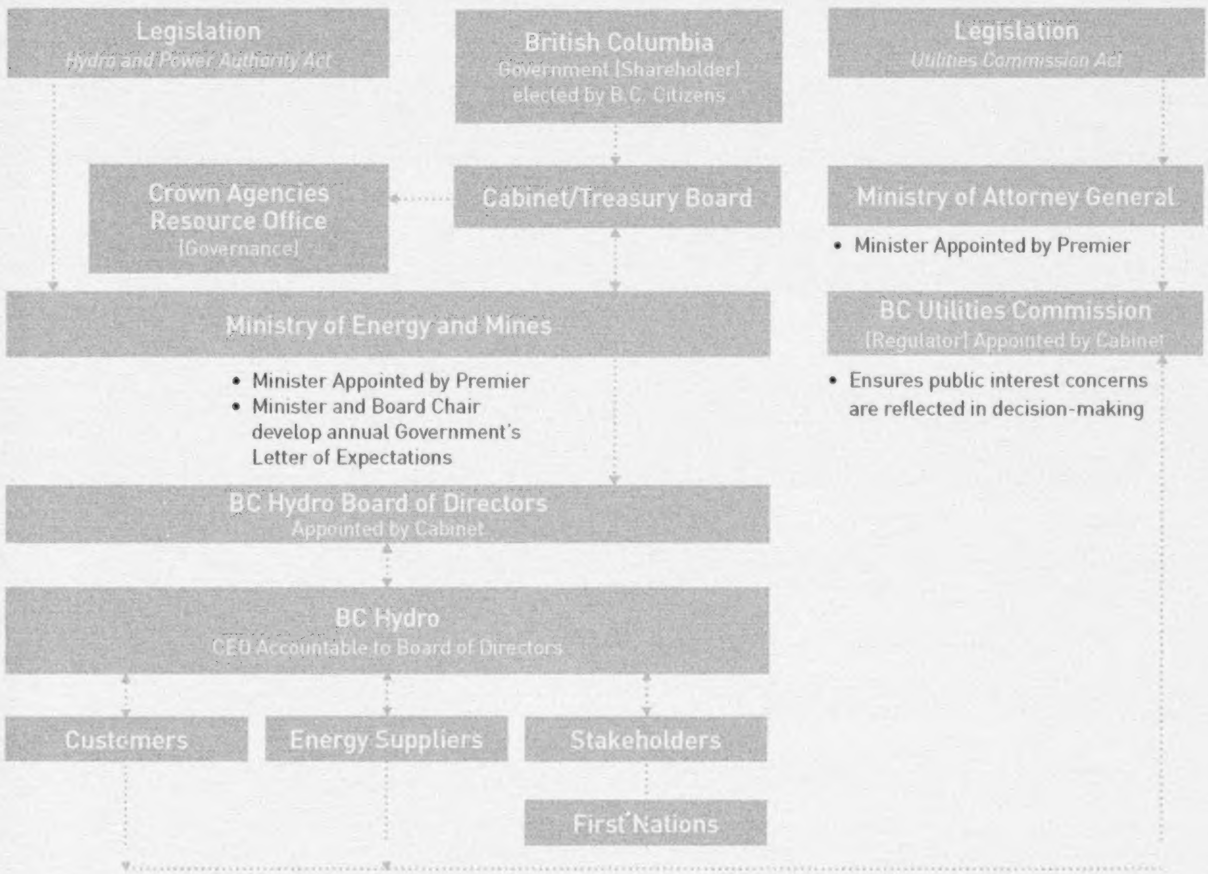
MAINTAIN COMPETITIVE RATES

Risks that impact the Maintain Competitive Rates objective are located in the Management's Discussion and Analysis.

OUR CAPACITY TO ACHIEVE RESULTS

In fiscal 2014, staffing levels did not affect BC Hydro's ability to meet performance targets. While some targets were not met, capacity was not a factor. In addition, BC Hydro was able to look for additional efficiencies that did not directly impact the execution of our strategies.

SHAREHOLDER-REGULATORY RELATIONSHIP FRAMEWORK



ENABLING LEGISLATION

Hydro and Power Authority Act	*Utilities Commission Act*	*BC Hydro Public Power Legacy and Heritage Contract Act*
This is the long-standing piece of legislation governing BC Hydro. This *Act* gives BC Hydro its mandate: to generate, manufacture, conserve, supply, acquire, and dispose of power and related products.	The *Act* gives the British Columbia Utilities Commission (BCUC) the power to regulate BC Hydro to ensure customers receive safe, reliable and non-discriminatory energy services at fair rates and the Province, as Shareholder, is afforded a reasonable opportunity to earn a fair return on its invested capital.	The *Act* ensures public ownership of BC Hydro's heritage resources, which include BC Hydro's transmission and distribution systems, and all of BC Hydro's existing generation and storage assets. The Province's 2007 BC Energy Plan lays out the general energy policies. BC Hydro is required to follow and the 2010 *Clean Energy Act* (*CEA*) updated several elements and targets included in that plan and provided further guidance for how BC Hydro is to meet the Province's energy objectives.
http://www.bclaws.ca/civix/document/id/complete/statreg/96212_01	http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/00_96473_01	http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/00_03086_01

GOVERNMENT'S LETTER OF EXPECTATIONS

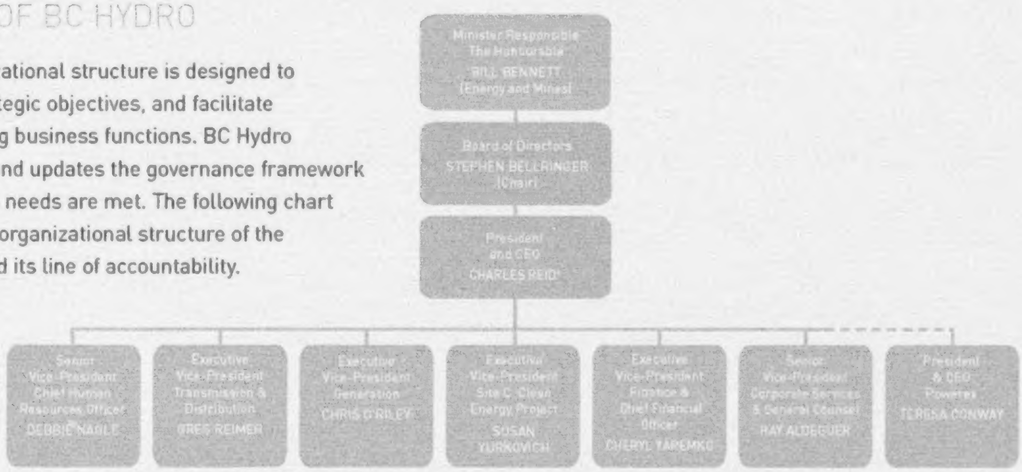
The *B.C. Government's Letter of Expectations* (*GLE*) describes the relationship between BC Hydro and the Province, and sets out objectives that the Province wishes BC Hydro to achieve. http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/openness-accountability/governments-letter-of-expectations.pdf

The Objectives laid out in the 2013 Letter and BC Hydro's accomplishments are outlined below:

Government Objectives for BC Hydro	BC Hydro's action
BC Hydro will work to implement the Integrated Resource Plan approved by the Shareholder.	BC Hydro filed the Final Draft Integrated Resource Plan submission with government in November 2013 and the IRP was approved shortly thereafter.
Consistent with the recommendations of the BC Hydro Review Panel, BC Hydro will continue to work to find cost savings and maintain competitive rates by efficiently and responsibly managing the business.	BC Hydro completed all of the 50 recommendations directed to BC Hydro by the end of March 2014. For example, BC Hydro delivered its planned operating cost savings of $391 million over the three year rate filing period of fiscal 2012 to 2014, and the fiscal 2014 target reductions for headcount and resulting labour savings were also achieved.
Work in collaboration with the Shareholder to ensure that adequate supplies of electricity are available to support new investments in liquefied natural gas and mines, consistent with *Canada Starts Here: The BC Jobs Plan*.	BC Hydro has prepared to supply the electricity requirements of the LNG industry. Under the government's LNG strategy, proponents are required to contribute capital for infrastructure development and to the electricity supply required to serve each operation. BC Hydro and government have continued commercial discussions with LNG proponents who have requested electricity supply. Ultimately, industry will decide what energy source they use to power operations. BC Hydro's Integrated Resource Plan also includes an expected LNG load to be served by BC Hydro of 360 MW (3,000 GWh). In support of mining development, BC Hydro entered into an innovative contractual arrangement with Imperial Metals for a transmission extension to serve the Red Chris mine. Under the agreement, Imperial Metals builds the transmission line to BC Hydro standards and then transfers it to BC Hydro ownership for a pre-determined price.
BC Hydro will advance Site C through the environmental assessment process, including consultation and input by the public, Aboriginal groups, communities in the region, property owners and stakeholders. BC Hydro-led consultations for Site C are proceeding to ensure regulatory timelines are met, and will be coordinated with other Natural Resource Sector consultations being undertaken by the Shareholder.	The Site C Clean Energy Project is undergoing a cooperative federal-provincial environmental assessment, which included a Joint Review Panel process. BC Hydro submitted a Site C Environmental Impact Statement in January 2013. The project entered the Panel stage in August 2013 and a public hearing process took place between December 9, 2013 and January 23, 2014. The Panel stage concluded in May 2014 with the submission of a Joint Review Panel report to federal and provincial governments. The report of the Joint Review Panel, along with other relevant information, will be considered by the federal and provincial governments as part of their decision making process for the Site C project. A decision on environmental certification is expected in the fall of 2014.

EXECUTIVE OF BC HYDRO

BC Hydro's organizational structure is designed to deliver on our strategic objectives, and facilitate coordination among business functions. BC Hydro regularly reviews and updates the governance framework to ensure business needs are met. The following chart shows the current organizational structure of the Executive Team and its line of accountability.



[1] *As of July 14, 2014, Jessica McDonald replaces retiring President and CEO, Charles Reid.*

GOVERNANCE FRAMEWORK

BC Hydro is committed to best practices in corporate governance as they provide for greater public accountability and transparency.

BC Hydro's practices, policies and the activities of its Board are in accordance with the *Governance and Disclosure Guidelines for Governing Boards of B.C. Public Sector Organizations*, issued by the B.C. Provincial Government in February 2005. These guidelines can be found at: http://www.fin.gov.bc.ca/brdo/governance/corporateguidelines.pdf.

BC Hydro complies with all of the disclosure requirements found in the Guidelines referenced above. This information can be found at: www.bchydro.com/about/who_we_are/board_of_directors.html and www.bchydro.com/about/who_we_are/committees.html. The governance framework is reviewed regularly to ensure it meets BC Hydro's ongoing business needs, while being consistent with the government's guidelines.

BC HYDRO BOARD OF DIRECTORS

The BC Hydro Board of Directors oversees the conduct of business and supervises management, which in turn is responsible for the day-to-day operations of BC Hydro. Directors are appointed by the B.C. Cabinet to bring special skills and experience to the Board's deliberations.

CHAIR: Stephen Bellringer

MEMBERS[1]**:** Bill Adsit[2], Kim Baird[3], Brad Bennett, Larry Blain, James Brown, James Hatton, John Knappett, Tracey McVicar, Janine North, John Ritchie

The Board's broad responsibilities includes endorsing a strategy for BC Hydro, monitoring strategy implementation, ensuring effective controls are in place and understanding the principal risks regarding the Company's business together with the associated management and mitigation plans.

The links below provide further information about BC Hydro's Board of Directors and its committees:

www.bchydro.com/about/who_we_are/board_of_directors.html

www.bchydro.com/about/who_we_are/committees.html

---

1 Jack Weisgerber was appointed to the Board on June 6, 2014. His appointment will be reflected in the 2015 Annual Report.

2 Bill Adsit was added to the Board on November 25, 2013. In May 2014, he became a member of the Audit and Finance Committee.

3 Kim Baird resigned from the Board of Directors Feb 15, 2014.

BOARD COMMITTEES[1]

AUDIT AND FINANCE COMMITTEE **Chair:** Tracey McVicar **Members:** Larry Blain, James Brown	**Purpose:** The Audit and Finance Committee assists the Board in fulfilling its obligations and oversight responsibilities relating to the audit process, financial reporting, treasury, information technology and telecommunications, the system of corporate controls and governance of the Corporation's pension plans. The Committee is also responsible for ensuring that principal risks associated with these issues are appropriately identified, monitored and managed.
CAPITAL PROJECTS COMMITTEE **Chair:** John Ritchie **Members:** Brad Bennett, James Hatton, John Knappett	**Purpose:** The Capital Projects Committee assists the Board of Directors in fulfilling its obligations and oversight responsibilities relating to the Corporation's long-term capital plans, capital budgets and capital projects, including dam safety, and Aboriginal relations & negotiations. The Committee is also responsible for ensuring that principal risks associated with these issues are appropriately identified, monitored and managed.
CONSERVATION AND CLIMATE ACTION COMMITTEE[2] **Chair:** Janine North **Members:** Kim Baird[3], James Hatton, Tracey McVicar	**Purpose:** The Conservation and Climate Action Committee assists the Board by monitoring and directing the environmental performance of the Corporation and monitoring and supporting the implementation of an energy conservation strategy as described in the BC Energy Plan. The Committee also provides guidance and direction to management and makes recommendations to the Board regarding initiatives and programs related to meeting the Corporation's environmental goals. The Committee is also responsible for ensuring the principal risks associated with these issues are appropriately identified, monitored and managed.
CORPORATE GOVERNANCE COMMITTEE **Chair:** Brad Bennett **Members:** All Directors	**Purpose:** The Corporate Governance Committee is structured as a Committee of the Whole. This means that its membership includes all Directors. Nonetheless, the Committee has independent Terms of Reference and is responsible for ensuring that BC Hydro and its Board develops and implements an effective approach to corporate governance which enables the business and affairs of the Corporation to be carried out, directed and managed with the objective of enhancing shareholder value. The Committee is also responsible for ensuring the principal risks associated with these issues are appropriately identified, monitored and managed.
EXECUTIVE COMMITTEE **Chair:** Stephen Bellringer **Members:** Kim Baird[3], Brad Bennett, Larry Blain, Janine North, Tracey McVicar, John Ritchie	**Purpose:** The Executive Committee only meets in special circumstances. It has the full powers of the Board to act in situations when, for timing reasons, a Board meeting cannot be scheduled.
ENERGY PLANNING AND PROCUREMENT COMMITTEE[4] **Chair:** Larry Blain **Members:** Brad Bennett, Janine North, John Ritchie	**Purpose:** The Energy Planning and Procurement Committee provides advice and direction to the Corporation on its strategic direction relating to resource planning, export strategy, economic development, and energy procurement activities, and on its execution of related initiatives. In addition, the Committee provides advice and support to the Board Chair in his or her dealings with government pertaining to these issues. The Committee is also responsible for ensuring that principal risks associated with these issues are appropriately identified, monitored and managed.
HUMAN RESOURCES AND SAFETY COMMITTEE[5] **Chair:** Kim Baird[3], Janine North[6] **Members:** Janine North[6], Stephen Bellringer	**Purpose:** The Human Resources and Safety Committee assists the Board in fulfilling its obligations relating to human resources and compensation issues, related specifically to senior management and generally to the Corporation. The Committee also provides advice and direction on safety issues, and monitors safety performance. The Committee is also responsible for ensuring that principal risks associated with these issues are appropriately identified, monitored and managed.
SHAREHOLDER RELATIONS COMMITTEE[7] **Chair:** Stephen Bellringer **Members:** Brad Bennett, Janine North	**Purpose:** The Shareholder Relations Committee assists the Board by ensuring that the Corporation's strategies and operating plans are in alignment with Shareholder expectations. The Committee is also responsible for ensuring that principal risks associated with these issues are appropriately identified, monitored and managed.

1 The Board Chair is an ex-officio member of all committees.

2 The *Conservation and Climate Action Committee* was disbanded on January 30, 2014 and elements of its mandate transferred to the *Safety, Human Resources and Environment Committee* and the *Energy Planning, Conservation and Procurement Committee*. The names of these Committees were amended as shown here as at the same date.

3 Kim Baird resigned from the Board of Directors February 15, 2014.

4 This Committee was renamed as the Energy Planning, Conservation and Procurement Committee on January 30, 2014 and its mandate was amended to incorporate conservation matters at that time.

5 This Committee was renamed as the Safety, Human Resources and Environment Committee on January 30, 2014 and its mandate was amended to incorporate environmental matters at that time.

6 Janine North became Chair of this Committee effective February 15, 2014.

7 This Committee was created on September 18, 2013.

INFORMATION ON SUBSIDIARIES

BC HYDRO SUBSIDIARIES

POWEREX CORPORATION

Powerex Corp. is a wholly-owned subsidiary of BC Hydro and a key participant in energy markets across North America, buying and supplying wholesale power, renewable energy, natural gas, ancillary services, and financial energy products and services. Established in 1988 and operating out of Vancouver, its export, marketing and trade activities help manage BC Hydro's electric system resources and provide significant economic benefits to British Columbia.

Powerex supports BC Hydro's electric system requirements through importing and exporting energy as required in addition to meeting its own trade commitments. Powerex also markets, on behalf of the Province, the Canadian Entitlement to the Downstream Benefits of the Columbia River Treaty.

The Chief Executive Officer (CEO) of Powerex reports directly to the Board of Directors of Powerex through the Chair of Powerex and works closely with the President & CEO of BC Hydro as a member of the Executive Team. The Chair of the Powerex Board, the Powerex CEO and BC Hydro's CEO, ensure the Board of BC Hydro is informed of Powerex's key strategies and business activities.

Powerex Directors:

Larry Blain (Chair); Stephen Bellringer; James Brown; and, James Hatton

Powerex's Senior Management includes:

Teresa Conway, President & CEO; Janette Lyons, Chief Financial Officer; and, Jay Ratzlaff, Chief Legal Officer.
Note: Jay Ratzlaff replaced John Irving as Chief Legal Officer effective December 16, 2013.

Powerex operates in complex and volatile energy markets, which can cause net income to vary significantly from year to year. Market, weather and economic conditions, reduced BC Hydro system flexibility, income timing differences and the strength of the Canadian dollar can materially impact Powerex net income. Over the previous five years, Powerex income has ranged from $8 to $244 million (fiscal 2009 to fiscal 2013). In fiscal 2014, Powerex's net income was $155 million pre-California litigation settlement and $(61) million post-California litigation settlement.

Powerex was one of over 60 sellers involved in the protracted litigation surrounding the western electricity markets in 2000-01. The majority of the 60 sellers have settled litigation around the power crisis in 2000-01. In Powerex's settlement Powerex admitted no wrongdoing: (1) resolved dozens of litigated regulatory and court proceedings and related appeals, with total claims against Powerex in excess of $3.2 billion (USD), which would not likely be concluded before 2018 or later, and avoided an estimated $50 million in future litigation expenses; (2) avoided the uncertainties of U.S. litigation, including an adverse FERC Administrative Law Judge (ALJ) decision on review before FERC and a pending trial before another FERC ALJ, and the possibility of additional remands to FERC by the Ninth Circuit of cases previously resolved in Powerex's favour; (3) avoided $125 million per year in interest accruals on potential refund amounts; and (4) allowed Powerex to focus on future business and trade relations with California. Due to the competitive nature of Powerex's business additional financial information is not disclosed as it could competitively harm Powerex. Please see the financial note disclosure for details of the California litigation settlement. For more information, visit powerex.com.

POWERTECH LABS INC.

Powertech Labs, operating in Surrey since its inception in 1979, is a wholly-owned subsidiary of BC Hydro. Powertech is internationally recognized as holding expertise in various fields of operation, and provides research and development, testing, technical services and advanced technology services to the international energy community including BC Hydro.

Powertech's Directors:

John Knappett (Chair), Brenda Eaton, and Nancy Olewiler. (Note: these Directors were replaced by Charles Reid[1], BC Hydro President and CEO; Greg Reimer, BC Hydro Executive Vice-President, Transmission and Distribution; and, Chris O'Riley, BC Hydro Executive Vice-President, Generation, effective March 1, 2014)

Powertech's Senior Management includes:

Powertech's Senior Management includes: Don Stuckert, Chief Executive Officer (CEO); and, Raymond Lings, Managing Director

Powertech's revenue for fiscal 2014 is $30 million with a net income of $3.8 million. In fiscal 2014 capital investment was $3.8 million with the focus split between service expansion and sustainment. For more information, visit powertechlabs.com.

OTHER SUBSIDIARIES

BC Hydro has created or retained a number of other subsidiaries for various purposes, including to hold licenses in other jurisdictions, to manage real estate holdings and to manage risks of various sorts. All the staff and management needs of these subsidiaries are fulfilled by BC Hydro employees, who perform these duties without additional remuneration. Three of these subsidiaries are considered active:

Subsidiary Name	BCHPA Captive Insurance Company Ltd.	Columbia Hydro Constructors	Tongass Power and Light Company
Primary Business	Procures insurance products and services on behalf of BC Hydro	Administers and supplies the labour force to specified projects	Provider of electrical power to Hyder, Alaska, due to its remoteness from the Alaska electrical system
Location of Operations (business address)	Vancouver, B.C.	Vancouver, B.C.	Vancouver, B.C.
Directors	Charles Reid[1]	Ray Aldeguer D. Garry Corbett	Ray Aldeguer Chris O'Riley
Sr. Management	Cheryl Yaremko – *CEO* James Le Lievre – *Treasurer* David Facey - *Secretary*	David Facey - *Secretary*	Ray Aldeguer - *President* Chris O'Riley – *Vice President* James Le Lievre – *Treasurer* David Facey - *Secretary*

BC Hydro's remaining subsidiaries either serve as nominee holding companies (indicated with *) or are considered to be inactive/dormant. These subsidiaries do not carry on active operations. As of March 31, 2014 these other subsidiaries consisted of the following:

1. BCH Services Asset Corp.
2. British Columbia Hydro International Limited
3. British Columbia Power Exchange Corporation
4. British Columbia Power Export Corporation
5. British Columbia Transmission Corporation
6. Burton Water Corporation (dissolved April 8/14)
7. Columbia Estate Company Limited*
8. Edgewood Water Corporation
9. Edmonds Centre Developments Limited*
10. Fauquier Water and Sewerage Corporation
11. Hydro Monitoring (Alberta) Inc.*
12. Waneta Holdings (US) Inc.*
13. West Robson Water Corporation (dissolved April 8/14)
14. Victoria Gas Company Limited

[1] *As of July 14, 2014, Jessica McDonald replaces retiring President and CEO, Charles Reid.*

BC HYDRO & POWER AUTHORITY MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) reports on British Columbia Hydro and Power Authority's (BC Hydro or the Company) consolidated results and financial position for the year ended March 31, 2014 (fiscal 2014) and should be read in conjunction with the Audited Consolidated Financial Statements and related notes of the Company for the years ended March 31, 2014 and 2013.

The Company applies accounting standards as prescribed by the Province of British Columbia ("the Province") which combines the accounting principles of International Financial Reporting Standards (IFRS) with regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980, *Regulated Operations* (ASC 980) (collectively the "Prescribed Standards"). All financial information is expressed in Canadian dollars unless otherwise specified.

This report contains forward-looking statements, including statements regarding the business and anticipated financial performance of the Company. These statements are subject to a number of risks and uncertainties that may cause actual results to differ from those contemplated in the forward-looking statements.

HIGHLIGHTS

- Net income after regulatory account transfers for the year ended March 31, 2014 was $549 million, $40 million above the prior fiscal year net income of $509 million. The increase from the prior year was primarily due to higher domestic revenues resulting from higher electricity prices, and lower materials and services expenses reflecting management's focus on cost reductions. These favourable variances were partially offset by higher amortization and depreciation expense due to higher assets in service.
- Revenues after regulatory transfers for the year were $5,392 million, $494 million higher than the prior year due to higher domestic revenues of $281 million due to higher average customer rates and higher trade revenues of $213 million due to higher electricity and gas prices.
- Fiscal 2014 water inflows were significantly lower than the prior fiscal year. The system inflow energy equivalent for fiscal 2014 was 95 per cent of average. The system inflow energy equivalent for fiscal 2013 was 109 per cent of average, but actual inflows were higher because both Williston and Kinbasket reservoirs spilled surplus water and there was some economic spill due to negative market prices. In contrast, fiscal 2014 experienced below average inflows and higher market prices.
- On October 4, 2013, the Federal Energy Regulatory Commission (FERC) issued an Order approving the settlement between Powerex and the California parties arising from events and transactions in the California power market during the 2000 and 2001 period. The settlement will become final upon the Settlement Effective Date specified in the settlement agreement, which is anticipated to occur in fiscal 2015. As part of the settlement, Powerex made a net cash payment into escrow of US$273 million, which translated to CDN$302 million as at March 31, 2014.
- Capital expenditures for the year ended March 31, 2014 were $2,036 million, a $107 million increase over prior fiscal year capital expenditures of $1,929 million. BC Hydro continues to invest significantly to refurbish its ageing infrastructure and build new assets for future growth, including the Mica Units 5 & 6 Project, G.M. Shrum Units 1 to 5 Turbine Rehabilitation, Ruskin Dam and Powerhouse Upgrade, Smart Metering and Infrastructure (SMI), Northwest Transmission Line Project, Interior to Lower Mainland Transmission Project, and Dawson Creek/Chetwynd Area Transmission Project.

CONSOLIDATED RESULTS OF OPERATIONS

for the years ended March 31 (in millions)	2014	2013	Change
Total Revenues	$ 5,392	$ 4,898	$ 494
Net Income	$ 549	$ 509	$ 40
Capital Expenditures	$ 2,036	$ 1,929	$ 107
GWh Sold (Domestic)	53,018	57,012	(3,994)

as at March 31 (in millions)	2014	2013	Change
Total Assets	$ 25,711	$ 23,782	$ 1,929
Shareholders' Equity	$ 3,865	$ 3,500	$ 365
Accrued Payment to the Province	$ 167	$ 215	$ (48)
Retained Earnings	$ 3,751	$ 3,369	$ 382
Debt to Equity	80 : 20	80 : 20	n/a
Number of Domestic Customers	1,914,549	1,892,685	21,864
Total Reservoir Storage (GWh)	12,855	13,261	(406)

REVENUES

Total revenue after regulatory account transfers for the year ended March 31, 2014 was $5,392 million, an increase of $494 million or 10 per cent compared to the prior fiscal year primarily due to higher domestic and trade revenues resulting from higher electricity and gas prices.

	(in millions)		*(gigawatt hours)*		*($ per MWh)*[2]	
for the years ended March 31	2014	2013	2014	2013	2014	2013
Domestic						
Residential	$ 1,663	$ 1,612	17,965	17,703	$ 92.57	$ 91.06
Light industrial and commercial	1,489	1,436	18,501	18,384	80.48	78.11
Large industrial	687	642	13,994	13,508	49.09	47.53
Other energy sales	275	322	2,558	7,417	107.51	43.41
Total Domestic Revenue Before Regulatory Transfer	4,114	4,012	53,018	57,012	77.60	70.37
Rate smoothing and load variance regulatory transfer	205	26	-	-	-	-
Total Domestic	$ 4,319	$ 4,038	53,018	57,012	$ 81.46	$ 70.83
Trade						
Electricity - Gross	$ 1,147	$ 914	23,806	30,975	$ 48.18	$ 29.51
Less: forward electricity purchases	(281)	(187)	-	-	-	-
Electricity - Net	866	727	-	-	-	-
Gas - Gross	1,144	817	26,276	28,982	43.54	28.19
Less: forward gas purchases	(937)	(684)	-	-	-	-
Gas - Net	207	133	-	-	-	-
Total Trade[1]	$ 1,073	$ 860	50,082	59,957	$ 21.42	$ 14.34
Total Revenues	$ 5,392	$ 4,898	103,100	116,969	$ 52.30	$ 41.87

[1] *Trade revenue regulatory transfer is netted with the trade cost of energy transfer to reflect a trade margin transfer.*
[2] *The Trade $/MWh figures are based on total gross sales which includes physical and financial transactions whereas the volumes only include physical transactions.*

DOMESTIC REVENUES

Total domestic revenues before regulatory account transfers for the year ended March 31, 2014 were $4,114 million, an increase of $102 million or three per cent over the prior fiscal year. The increase was due mainly to higher average customer rates, increased consumption by residential, light industrial and commercial, and large industrial customers, partially offset by lower surplus sales.

Average customer rates were higher in fiscal 2014 compared to the prior fiscal year, reflecting an average rate increase as approved by the British Columbia Utilities Commission (BCUC) for fiscal 2014 of 1.44 per cent.

Increased consumption by the residential class was primarily driven by customer growth and the impact of colder weather, partially offset by lower usage per account. Gigawatt hours sold were higher in the light industrial and commercial customer class mainly due to increased activity in the manufacturing, services, and commercial real estate sectors. Higher gigawatt hours sold to the large industrial customer class was mainly due to the start up and expansion of several metal mines. Other energy sales were significantly lower than the prior fiscal year due to lower water inflows in the current fiscal year. In the prior fiscal year, unusually high water inflows in the summer months resulted in high reservoir levels. To manage the risk of spill, greater hydro energy was generated and sold. Surplus energy sales were 1,008 GWh for the year ended March 31, 2014, compared to 6,020 GWh in the prior fiscal year.

Variances between actual and planned load are deferred to the Non-Heritage Deferral Account (NHDA) and variances between actual and planned other energy sales are deferred to either the Heritage Deferral Account (HDA) or NHDA.

TRADE REVENUES

Powerex, a wholly owned subsidiary of the Company, is a key participant in energy markets across North America, buying and supplying wholesale power, natural gas, ancillary services, financial energy products, and environmental products with an expanding list of trade partners.

The Company's electricity system is interconnected with systems in Alberta and the Western United States, facilitating sales and purchases of electricity outside of British Columbia. Powerex's trade activities help the Company balance its system by being able to import energy to meet domestic demand when there is a supply shortage and exporting energy when there is a supply surplus. Exports are made only after ensuring domestic demand requirements can be met.

Total trade revenue for the year ended March 31, 2014 was $1,073 million, an increase of $213 million compared with the same period in the prior year. The increase in revenue was primarily due to a 55 per cent increase in the average electricity sales price and a 51 per cent increase in the average gas sales price. The increase in the average electricity sales price in the current year was primarily due to low market prices in the Pacific Northwest in the prior year due to higher water levels. The increase in the average gas sales price in the current fiscal year reflects increases in natural gas prices in North America due to increased demand. These increases were partially offset by a 16 per cent reduction in gigawatt hours sold over the same period in the prior year primarily due to lower volumes of surplus energy sold from BC Hydro as a result of lower water levels. Variances between actual and planned trade income (which includes trade revenues) are deferred to the Trade Income Deferral Account (TIDA).

OPERATING EXPENSES

For the year ended March 31, 2014, total operating expenses of $4,245 million were $396 million higher than in the prior fiscal year. The increase over the prior year was due primarily to higher expenditures on electricity and gas purchases, consistent with higher electricity and gas sales, and higher amortization and depreciation expense due primarily to higher assets in service.

COST OF ENERGY

Energy costs are comprised of electricity and gas purchases for domestic and trade customers, water rentals and transmission and other charges. Energy costs are influenced primarily by the volume of energy consumed by customers, the mix of sources of supply and market prices of energy. The mix of sources of supply is influenced by variables such as the current and forecast market prices of energy, water inflows, reservoir levels, energy demand, and environmental and social impacts.

Total energy costs after regulatory account transfers for the year ended March 31, 2014 were $2,146 million, $340 million or 19 per cent higher than in the prior fiscal year. The increase over the prior fiscal year was primarily due to lower water inflows and system constraints in the current fiscal year, more Independent Power Producers (IPPs) achieving commercial operations, higher thermal generation, and higher trade electricity and gas purchase prices.

	(in millions)		*(gigawatt hours)*		*($ per MWh)*	
for the years ended March 31	**2014**	2013	**2014**	2013	**2014**[2]	2013[2]
Domestic						
Water rental payments (hydro generation)[1]	**$ 372**	$ 348	**45,225**	52,143	**$ 8.42**	$ 7.15
Purchases from Independent Power Producers	**825**	760	**11,025**	10,675	**74.82**	71.23
Other electricity purchases - Domestic	**42**	10	**918**	359	**45.60**	28.00
Gas for thermal generation	**43**	29	**268**	122	**161.89**	237.69
Transmission charges and other expenses (recoveries)	**11**	12	**117**	113	**-**	-
Non-treaty storage/Libby Coordination Agreement	**(15)**	(57)	**-**	-	**-**	-
Allocation (to) from trade energy	**29**	(21)	**1,365**	(883)	**32.30**	22.51
Total Domestic Cost of Energy Before Regulatory Transfers	**1,307**	1,081	**58,918**	62,529	**22.18**	17.29
Domestic cost of energy regulatory transfers	**(55)**	42	**-**	-	**-**	-
Total Domestic	**$ 1,252**	$ 1,123	**58,918**	62,529	**$ 21.25**	$ 17.96
Trade						
Electricity - Gross	**$ 792**	$ 539	**25,013**	29,824	**$ 31.66**	$ 18.07
Less: forward electricity purchases	**(281)**	(187)	**-**	-	**-**	-
Electricity - Net	**511**	352	**-**	-	**-**	-
Remarketed gas - Gross	**1,086**	793	**26,754**	29,198	**40.59**	27.16
Less: forward gas purchases	**(937)**	(684)	**-**	-	**-**	-
Remarketed gas - Net	**149**	109	**-**	-	**-**	-
Transmission charges and other expenses	**227**	209	**-**	-	**-**	-
Allocation from (to) domestic energy	**(29)**	21	**(1,365)**	883	**32.30**	22.51
Total Trade Cost of Energy Before Regulatory Transfers	**858**	691	**50,402**	59,905	**20.97**	13.31
Trade net margin regulatory transfer	**36**	(8)	**-**	-	**-**	-
Total Trade	**$ 894**	$ 683	**50,402**	59,905	**$ 21.68**	$ 13.17
Total Energy Costs	**$ 2,146**	$ 1,806	**109,320**	122,434	**$ 21.45**	$ 15.62

[1] *Total GWh is net of storage exchange.*

[2] *Total cost per MWh includes other electricity purchases at gross cost.*

Domestic Energy Costs

Domestic energy costs before regulatory transfers of $1,307 million for the year ended March 31, 2014 were $226 million higher than in the prior fiscal year. The increase was the result of lower water inflows and system constraints in the current fiscal year and more IPPs achieving commercial operations. Water transactions related to the Non-Treaty Storage Agreement and Libby Coordination Agreement did not reduce cost of energy as much as compared to the prior fiscal year due to fewer market opportunities to capitalize on storage flexibility.

In the current fiscal year, due to lower inflows, there was less hydro generation. In the prior year, unusually high inflows resulted in a shortage of storage capacity requiring increased generation which resulted in higher surplus sales. Further, due to system constraints resulting from plant outages and colder weather, greater market electricity purchases were required. Allocation from trade was also higher due to increased net trade energy imports resulting from more purchase opportunities because of hydro conditions and favourable market prices.

Water rental payments are based on the prior year's generation. In the prior fiscal year, due to very high inflows, high reservoir levels and to manage the risk of spill, greater hydro energy was generated, resulting in a higher average cost per MWh when applied to the current year's lower hydro generation. Water rental rates are indexed each calendar year based on the annual percentage change in British Columbia's consumer price index.

Higher costs for thermal generation were the result of increased use of Burrard generating station because of system constraints and higher generation at the Fort Nelson generating station in the current year because of fewer economic opportunities to import from the Alberta Power pool as compared to the prior fiscal year.

The Company has an agreement with Bonneville Power Administration (BPA) to operate Non-Treaty Storage at Kinbasket reservoir. Under the agreement, when the Company releases water from its portion of Non-Treaty Storage it is entitled to the value of additional energy flowing through the U.S. Federal Columbia River, as determined by the market price of energy at that time which is reflected as a reduction to cost of energy. During the current fiscal year, the Company released less water than the prior fiscal year because there was less water in storage than the prior year due to lower water inflows and previous releases. As a result, the reduction to cost of energy for the current fiscal year was only $3 million compared to $56 million in the prior fiscal year. The prior year also included $31 million for the value of net releases earned from the effective date of the agreement (September 1, 2011) to the date the contract was signed (April 22, 2012).

On September 27, 2013, the Company entered into a short-term Agreement with BPA and the U.S. Army Corps of Engineers on coordination of Libby project operations. This agreement and its operations are similar to the Non-Treaty Storage Agreement. During the current fiscal year, the Company's water transactions resulted in a reduction to cost of energy in the amount of $11 million.

Variances between actual and planned domestic cost of energy are transferred to the HDA and NHDA.

Trade Energy Costs

Total trade energy costs before regulatory account transfers for the year ended March 31, 2014 were $858 million, an increase of $167 million compared with the same period in the prior year. Trade purchase costs increased primarily due to a 75 per cent increase in the average electricity purchase price and a 49 per cent increase in the average gas purchase price. The increase in the average electricity purchase price in the current year was primarily due to low market prices in the Pacific Northwest in the prior year due to higher water levels. The increase in the average gas purchase price reflects increases in natural gas prices in North America due to increased demand. These increases were partially offset by a 16 per cent reduction in gigawatt hours purchased over the same period in the prior year primarily due to lower volumes of surplus energy as a result of lower water levels. Variances between actual and planned trade income (which includes trade energy costs) are deferred to the TIDA.

Water Inflows

Fiscal 2014 inflows were significantly lower than the prior fiscal year. The system inflow energy equivalent for fiscal 2014 was 95 per cent of average, with Williston and Kinbasket reservoirs at 91 and 107 per cent of average, respectively. The system inflow energy equivalent for fiscal 2013 was 109 per cent of average, but actual inflows were higher because both Williston and Kinbasket reservoirs spilled surplus water; in addition, there was some economic spill due to negative market prices. In contrast, fiscal 2014 experienced below average inflows and higher market prices.

The Company's reservoirs have been managed such that system energy storage on March 31, 2014 was 11,600 GWh, or 700 GWh below the 10 year historic average. This was 400 GWh lower than the system energy storage of 12,000 GWh recorded one year earlier. The Williston and Kinbasket reservoir energy contents were 8,500 GWh (800 GWh below the 10 year historic average) and 3,100 GWh (100 GWh above the 10 year historic average), respectively, with Williston 1,000 GWh lower than the prior year and Kinbasket 600 GWh higher than the prior year.

PERSONNEL EXPENSES

Personnel expenses include labour, benefits and post employment benefits for employees of the Company. Personnel costs for the year ended March 31, 2014 were $538 million, $11 million higher than in fiscal 2013, primarily due to higher current service pension costs due to a decrease in the discount rate used to calculate pension cost.

MATERIALS AND EXTERNAL SERVICES

Expenditures on materials and external services for the year ended March 31, 2014 of $579 million were $27 million lower than in the prior fiscal year, primarily due to decreased services and other operational activities.

CAPITALIZED COSTS

Capitalized costs consist of overhead costs directly attributable to capital expenditures that are transferred from operating costs to property, plant and equipment (PP&E). Overhead costs not eligible for capitalization under IFRS are transferred from operating costs to the IFRS PP&E regulatory account. The annual transfers to the IFRS PP&E regulatory account are amortized over 40 years which approximates the composite average life of the PP&E. In addition, the ongoing impact of this change is being smoothed into rates over a 10 year period through transfers to the IFRS PP&E regulatory account. As such, each year, 1/10 more of ineligible costs will be charged to operating costs such that by the end of year ten, all ineligible costs will be charged to operating costs. Capitalized costs to either PP&E or the associated regulatory accounts for the year ended March 31, 2014 were $244 million, $15 million lower than capitalized costs of $259 million in the same period in the prior fiscal year.

AMORTIZATION AND DEPRECIATION

Amortization and depreciation expense includes the depreciation of property, plant and equipment, intangible assets, and the amortization of certain regulatory accounts. For the year ended March 31, 2014, amortization and depreciation expense was $995 million, $42 million or four per cent higher than in the prior fiscal year primarily due to higher assets in service in the current year.

GRANTS AND TAXES

As a Crown Corporation, the Company is exempt from paying federal and provincial income taxes, but pays local government taxes and grants in lieu to municipalities and regional districts, and school tax to the Province on certain assets. Total grants and taxes for the year ended March 31, 2014 of $203 million were comparable to total grants and taxes of $196 million in the prior fiscal year.

OTHER COSTS, NET OF RECOVERIES

Other costs, net of recoveries primarily include gains and losses on the disposal of assets and certain cost recoveries classified as operating costs. For the year ended March 31, 2014, other costs net of recoveries of $28 million were comparable to $20 million in the prior fiscal year.

FINANCE CHARGES

Finance charges after net regulatory transfers for the year ended March 31, 2014 of $598 million were $58 million or 11 per cent higher than in the prior fiscal year. The increase is primarily due to higher planned volume of debt issues and revolving borrowings, higher planned short term interest rates and higher planned lease charges. The increase was partially offset by higher planned capitalized interest during construction.

REGULATORY TRANSFERS

The Company presents its results and financial position under the Prescribed Standards. Under the Prescribed Standards, the Company applies the principles of IFRS combined with ASC 980 to reflect the rate-regulated environment in which the Company operates. These Prescribed Standards allow for the deferral of costs and recoveries that under IFRS would otherwise be included in the determination of comprehensive income in the year the amounts are incurred. The deferred amounts are either recovered or refunded through future rate adjustments.

The use of regulatory accounts is common amongst regulated utility industries throughout North America. BC Hydro uses various regulatory accounts, in compliance with BCUC orders, in order to better match costs and benefits for different generations of customers, smooth out the rate impact of large non-recurring costs, and defer to future periods differences between forecast and actual costs or revenues. Regulatory accounts allow the Company to defer certain types of revenue and cost variances through transfers to and from the accounts which would otherwise be included in net income or other comprehensive income, unless otherwise recovered through rates. The deferred amounts are then included in customer rates in future periods, subject to approval by the BCUC.

Net regulatory account transfers are comprised of the following:

for the years ended March 31 (in millions)	2014	2013
Energy Accounts		
Heritage Deferral	$ 50	$ (124)
Non-Heritage Deferral	(3)	102
Trade Income Deferral	171	15
	218	(7)
Forecast Variance Accounts		
Finance Charges	(80)	(48)
Rate Smoothing Account	111	(41)
Non-Current Pension Cost	(247)	184
Other	14	(4)
	(202)	91
Capital-Like Accounts		
Demand Side Management (DSM)	118	148
Site C	67	67
Smart Metering and Infrastructure (SMI)	75	93
IFRS Property, Plant and Equipment	179	197
	439	505
Non-Cash Accounts		
Environmental Provisions	22	52
First Nations	42	17
Other	8	7
	72	76
Amortization of regulatory accounts	(319)	(321)
Interest on regulatory accounts	57	55
Net change in regulatory accounts	$ 265	$ 399

For the year ended March 31, 2014, net additions to the Company's regulatory accounts after amortization were $265 million compared to prior year net additions of $399 million. The net asset balance in the regulatory asset and liability accounts as at March 31, 2014 was an asset of $4,699 million compared to an asset of $4,434 million at March 31, 2013.

Net additions to the regulatory accounts during the year ended March 31, 2014 included:

- Increases to the energy deferral accounts primarily due to the California litigation settlement, more domestic and net trade imports, as well as less surplus sales due to lower water inflows;
- Planned expenditures on DSM projects, which support energy conservation, the Site C project and SMI;
- Transfers to the IFRS Property, Plant and Equipment regulatory account for smoothing the rate impact of overhead costs not eligible for capitalization under IFRS as they are not considered directly attributable to the construction of capital assets; and
- The Rate Smoothing regulatory liability account to smooth the rate increases over the three years covered by the Amended F2012-F2014 Revenue Requirements Application. The balance of the Rate Smoothing regulatory account has been fully drawn down to $nil as of March 31, 2014.

These net additions were partially offset by:

- Transfers to the Non-Current Pension Cost regulatory account for variances that arise between forecast and actual non-current pension and other post-employment benefit costs, which would otherwise be included in operating expenses as well as actuarial gains and losses, which are primarily driven by changes in the year-over-year discount rates;
- The Finance Charges regulatory liability account due to favourable variances to the forecast; and
- Net amortization of the regulatory accounts.

Net regulatory account balances are as follows:

as at March 31 (in millions)	2014	2013
Energy Accounts		
Heritage Deferral Account	$ 105	$ 70
Non-Heritage Deferral Account	362	467
Trade Income Deferral Account	324	190
	791	727
Capital-Like Accounts		
Demand-Side Management Programs	788	733
Site C	338	258
Capital Project Investigation Costs	35	40
SMI	277	192
IFRS Property, Plant and Equipment	617	447
	2,055	1,670
Forecast Variance Accounts		
Rate Smoothing Account	-	(111)
Non-Current Pension Cost	280	544
Foreign Exchange Gains and Losses	(89)	(100)
CIA Amortization	81	75
Finance Charges	(79)	1
Other Forecast Variance Accounts	56	73
	249	482
Non-Cash Accounts		
First Nation Negotiations, Litigation and Settlement Costs	589	553
Environmental Provisions	383	367
Future Removal and Site Restoration Costs	(56)	(88)
IFRS Pension & Other Post-Employment Benefits	688	723
	1,604	1,555
Total Regulatory Account Balance	$ 4,699	$ 4,434

19 of 27 regulatory accounts, which represent approximately 80 per cent of the total regulatory account balance as at March 31, 2014, are being recovered in current rates.

COMPARISON WITH SERVICE PLAN

The *Budget Transparency and Accountability Act* requires that BC Hydro file a Service Plan each year. BC Hydro's Revised Service Plan filed in June 2013 forecast a net income for fiscal 2014 at $545 million and also incorporated the impacts of Special Direction No. 3 (issued by the Government to the BCUC on May 22, 2012) which, among other things, set the interim rate increase for fiscal 2014 at 1.44 per cent and the rate rider at 5 per cent. The Service Plan filed in February 2014 incorporated components of Direction No. 6 (issued by the Government to the BCUC on March 6, 2014) which, among other things, confirmed the fiscal 2014 rate increase of 1.44 per cent as final and confirmed the allowed effective rate of return on equity for fiscal 2014 as 11.84 per cent.

Domestic revenues were higher than the June 2013 Revised Service Plan due primarily to the classification of surplus sales of $102 million which for financial statement purposes were included in Domestic Revenue, but for the June 2013 Revised Service Plan were netted against Cost of Energy.

Powerex operates in complex and volatile energy markets which can cause net income to vary significantly from year to year. Market, weather and economic conditions, reduced BC Hydro system flexibility, income timing differences and the strength of the Canadian dollar can materially impact Powerex net income. As a result, significant variances to forecast are not unusual.

In fiscal 2014, there was an increase in natural gas prices in North America which resulted in a corresponding increase in electricity prices. As a result, both Powerex's Trade revenue and Trade cost of energy amounts were higher than the forecast in the June 2013 Revised Service Plan; however, the Trade gross margin was comparable. Variances to the June 2013 Revised Service Plan for Trade revenue and Trade cost of energy are both deferred through the cost of energy account.

Personnel, materials and external services expenditures, net of capitalized overhead costs, were comparable to the June 2013 Revised Service Plan, as were amortization expense, grants and taxes and finance charges. Other expense was higher than the June 2013 Revised Service Plan primarily due to some unplanned write-offs of cancelled projects and other provisions.

The table on the following page provides an overview of BC Hydro's fiscal 2014 financial performance results, relative to its June 2013 Revised Service Plan forecast. The results and forecasts form the basis upon which key financial performance targets are set.

Consolidated Statement of Operations

(in millions)	Actual		June 2013 Revised Service Plan	Variance to June 2013 Revised Service Plan	Forecast[1,3]		
	2013	2014	2014		2015	2016	2017
Revenues							
Domestic	$ 4,038	$ 4,319	$ 4,214	$ 105	$ 4,830	$ 5,060	$ 5,446
Trade	860	1,073	711	362	999	956	1,014
	4,898	5,392	4,925	467	5,829	6,016	6,460
Expenses							
Operating Costs							
Cost of energy	1,806	2,146	1,687	(459)	2,283	2,208	2,462
Other operating expenses							
Personnel expenses, materials and external services[2]	840	848	851	3	867	904	966
Amortization	953	995	1,003	8	1,204	1,241	1,217
Finance Charges	540	598	597	(1)	633	751	838
Grants and taxes	196	203	205	2	214	224	238
Other	54	53	37	(16)	46	37	37
	4,389	4,843	4,380	(463)	5,247	5,364	5,759
Net Income	$ 509	$ 549	$ 545	$ 4	$ 582	$ 652	$ 701

[1] *Forecast may not add due to minor rounding.*
[2] *These amounts are net of capitalized overhead and recoveries.*
[3] *BC Hydro Service Plan 2014/15 - 2016/17.*

PAYMENT TO THE PROVINCE

Under a Special Directive from the Province, the Company is required to make an annual payment to the Province (the Payment) on or before June 30 of each year. The Payment is equal to 85 per cent of the Company's net income for the most recently completed fiscal year unless the debt to equity ratio, as defined by the Special Directive, after deducting the Payment, is greater than 80:20. If the Payment would result in a debt to equity ratio exceeding 80:20, then the Payment is the greatest amount that can be paid without causing the debt to equity ratio to exceed 80:20. The Payment accrued for the year ended March 31, 2014 is $167 million which is below 85 per cent of the Company's net income due to the 80:20 cap.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the year ended March 31, 2014, was $815 million, compared with cash flow provided by operating activities of $888 million in the prior fiscal year. The decrease was primarily due to a decrease in cash flows from working capital mainly due to restricted cash related to the California litigation settlement. The decrease was partially offset by an increase in net income before regulatory transfers due to higher revenues, partially offset by higher energy costs.

The long-term debt balance net of sinking funds at March 31, 2014 was $15,568 million, compared with $14,022 million at March 31, 2013. The increase was mainly as a result of an increase in revolving borrowings of $1,189 million, an increase in net long-term bond issues totalling $1,011 million ($1,150 million par value), and net foreign exchange revaluation losses of $82 million. These increases were partially offset by long-term bond redemptions totalling $706 million par value, net gains on economic hedging activities of $14 million, amortization of premiums of $9 million and sinking fund income of $6 million. Long-term debt increased primarily to fund capital expenditures.

CAPITAL EXPENDITURES

Capital expenditures, which include property, plant and equipment and intangible assets, were as follows:

for the years ended March 31 (in millions)		2014		2013
Distribution improvements and expansion	$	335	$	309
Generation replacements and expansion		496		421
Transmission lines and substation replacements & expansion		912		758
Smart Metering and Infrastructure program		87		258
General, including technology, vehicles and buildings		206		183
Total Capital Expenditures	$	2,036	$	1,929

Total capital expenditures presented in this table are different from the amount of property, plant and equipment and intangible asset expenditures in the Consolidated Statement of Cash Flows due to the effect of accruals related to these expenditures.

Distribution capital expenditures for the year ended March 31, 2014 were $335 million, which included expenditures on customer driven work, end of life asset replacement, system expansion and improvement projects.

Generation capital expenditures for the year ended March 31, 2014 were $496 million, which included expenditures for Mica Unit 5 & 6 Installation, Ruskin Dam and Powerhouse Upgrade, John Hart Replacement, G.M. Shrum Units 1 to 5 Turbine Rehabilitation and Hugh Keenleyside Spillway Gate Upgrade projects.

Transmission lines and substations capital expenditures for the year ended March 31, 2014 were $912 million, which included expenditures on the Northwest Transmission Line, Interior to Lower Mainland Transmission Line, Dawson Creek/Chetwynd Area Transmission, Seymour Arms Series Capacitor Station, Vancouver City Central Transmission, Iskut Extension, and Surrey Area Substation projects.

SMI capital expenditures for the year ended March 31, 2014 were $87 million, which is $171 million below expenditures for the same period in the prior year as the SMI program was in full implementation in fiscal 2013, including the mass deployment of meters which is now complete. Currently, activities are focused around network equipment purchases and remaining meter installations.

General capital expenditures for the year ended March 31, 2014 were $206 million, which primarily included expenditures on various technology projects and facilities development and improvements.

LEGAL PROCEEDINGS

CALIFORNIA SETTLEMENT

On October 4, 2013, the Federal Energy Regulatory Commission issued an Order approving the settlement between Powerex and Pacific Gas and Electric, Southern California Edison, San Diego Gas and Electric, the California Attorney General, and the California Public Utilities Commission (the California Parties) arising from events and transactions in the California power market during the 2000 and 2001 period.

The settlement will become final upon the Settlement Effective Date specified in the settlement agreement, which is anticipated to occur in fiscal 2015.

As part of the settlement, Powerex made a net cash payment into escrow of US$273 million which translated to CDN$287 million on the transaction date and CDN$302 million as at March 31, 2014, which is recorded as restricted cash in the statement of financial position. The cash payment will remain in escrow until after occurrence of the Settlement Effective Date. The net cash payment was calculated as the difference between the agreed upon settlement amount of US$750 million and the receivables and interest owing from the California parties to Powerex of US$477 million. The net cash payment was

accounted for in the first quarter of fiscal 2014 and an expense of CDN$214 million was recorded. The expense was calculated on the transaction date as the net cash settlement amount of CDN$287 million (US$273 million) less amounts previously accrued related to legal claims of CDN$73 million. On March 6, 2014, the Province issued Direction No.7 to the BCUC which contained a provision that allows Powerex's net loss for fiscal 2014 to be deferred to the TIDA.

RATE REGULATION

In the process of regulating and setting rates for BC Hydro, the BCUC must ensure that the rates are sufficient to allow BC Hydro to provide reliable electricity service, meet its financial obligations, comply with government policy and achieve an annual rate of return on deemed equity (ROE). On March 6, 2014, the Government issued Directions No. 6 and No. 7 to the BCUC to implement the 10 year plan for BC Hydro announced on November 26, 2013, which is discussed further below.

BC HYDRO 10 YEAR PLAN

On November 26, 2013, the Government announced a 10 year plan for BC Hydro. On March 6, 2014, the Government issued Directions No. 6 and 7 to the BCUC to implement the 10 year plan. Direction No. 6 sets BC Hydro's rate increase at 9 per cent for fiscal 2015 and 6 per cent for fiscal 2016 and also specifies the amounts to be amortized from BC Hydro's regulatory accounts in those years. Direction No. 7 caps BC Hydro's rate increases for fiscal 2017, fiscal 2018 and fiscal 2019 at 4.0 per cent, 3.5 per cent and 3.0 per cent respectively, subject to a BCUC review. The BCUC will also set the rates for the final five years of the plan. In addition, Direction No. 6 requires the BCUC to set the ROE for fiscal 2014 at 11.84 per cent and Direction No. 7 sets the ROE at 11.84 per cent for fiscal 2015, fiscal 2016 and fiscal 2017. Furthermore, the Deferral Account Rate Rider will remain at 5 per cent for fiscal 2015 and future years.

BC HYDRO F2015-F2016 REVENUE REQUIREMENTS RATE APPLICATION (F15-F16 RRRA)

On March 7, 2014, BC Hydro filed its F15-F16 RRRA, subsequent to the issuance by Government of Directions No. 6 and 7. The F15-F16 RRRA sets rates for fiscal 2015 and fiscal 2016 at 9 per cent and 6 per cent respectively and also requested specific amounts to be amortized from BC Hydro's regulatory accounts. In addition, the F15-F16 RRRA requested the approval of two new regulatory accounts; a) the Rate Smoothing Regulatory Account (to smooth out rate increases over the 10 year period of the 10 year plan) and b) the Real Property Sales Regulatory Account to capture the variance between forecast and actual net gains from real property sales. BC Hydro also filed as an appendix to the F15-F16 RRRA its Regulatory Accounts Report. The BCUC issued Order No. G-48-14 on March 26, 2014, approving the application as filed.

AVAILABLE TRANSFER CAPACITY (ATC) RULE

On December 5, 2011, the Alberta Electric System Operator (AESO) filed a proposed rule with the Alberta Utilities Commission (AUC) to allocate ATC between the existing BC - Alberta intertie and new interties when the Alberta system is constrained and cannot accommodate the total ATC of all interties. BC Hydro participated in the hearing opposing the proposed rule. The AUC issued its decision on February 1, 2013 approving the rule as filed. The impact to BC Hydro of the approval of the ATC rule is a reduction in the effective transmission transfer capability between the provinces, which in turn reduces the ability of transmission customers, including Powerex, to sell energy into Alberta. On March 4, 2013, BC Hydro and Powerex filed a motion for leave to appeal the AUC decision with the Alberta Court of Appeal. BC Hydro and Powerex also filed a request for Review and Variance with the AUC on April 2, 2013. On August 16, 2013, the AUC issued its decision denying the request for Review and Variance. The motions for leave to appeal were heard on November 19, 2013 and on April 10, 2014, the Alberta Court of Appeal granted leave. BC Hydro and Powerex filed a Notice of Appeal on May 15, 2014 and expect that the appeal will be heard in fiscal 2015 with a decision expected by end of fiscal 2015.

NEW POWER PURCHASE AGREEMENT WITH FORTISBC

In May 2013, BC Hydro filed an application with the BCUC for approval of a new 20 year Power Purchase Agreement (PPA) with FortisBC. BC Hydro's current PPA with FortisBC has been in place since 1993 and expired on September 30, 2013. The BCUC extended the term of the PPA beyond September 30, 2013, until such time as the decision on the application was issued. BC Hydro and FortisBC have been in negotiations for a new agreement for several years. The BCUC conducted a written process to review the application and on December 13, 2013 requested additional submissions from BC Hydro, FortisBC and interveners in regards to the provisions of the PPA designed to protect BC Hydro against FortisBC and its self-generating customers who may engage in arbitrage opportunities. On May 6, 2014, the BCUC issued Order No. G-60-14 and approved the new PPA effective July 1, 2014, for a 20 year period.

APPLICATION FOR APPROVAL OF CHARGES RELATED TO METER CHOICES PROGRAM

On October 7, 2013, BC Hydro filed an application with the BCUC for approval of new charges related to its Meter Choices Program, pursuant to Government Direction No. 4 issued on September 25, 2013. The application requested approval of changes to BC Hydro's Electric Tariff that would allow BC Hydro to charge customers who choose to retain a legacy meter, or choose the radio-off option for their smart meters, a fee designed to recover the additional costs of meter options other than a smart meter. The application also requested approval of a regulatory account to capture the costs to BC Hydro of offering the meter choices program to its customers and approval to charge a failed installation charge to those customers who have a failed meter installation. On April 25, 2014, the BCUC issued its decision approving BC Hydro's charges, subject to minor adjustments to some of the requested charges.

RESIDENTIAL INCLINING BLOCK (RIB) RE-PRICING

In November 2013, BC Hydro filed an application seeking approval of new pricing principles for its RIB rate for fiscal 2015 and fiscal 2016 as the current pricing principles expired at the end of fiscal 2014. The new pricing principles would see rate increases applied equally to each of the basic charge, Step 1 and Step 2 energy prices. On February 4, 2014, the BCUC approved the new pricing principles as requested by BC Hydro.

RATE DESIGN APPLICATION (RDA)

BC Hydro is beginning the preparation of its next RDA, which is expected to be filed with the BCUC at the end of June 2015. Among other things, the 2015 RDA will consider and update many of the underlying drivers, analysis and assumptions that impact BC Hydro's conservation rates for residential, commercial and industrial customers. Government policy, BC Hydro's load resource balance and energy surplus, conservation results and customer experience with the rates will be considered, and may result in amendments or updates to the rates. BC Hydro will also consider the Industrial Electricity Policy Review recommendations with respect to the transmission stepped rate and transmission Time of Use rates, as well as changes to BC Hydro's long run marginal cost which is used in the pricing of step (tier) 2 energy blocks for the conservation rates.

RISK MANAGEMENT

As discussed earlier in this report, BC Hydro is exposed to numerous risks, which can result in safety, environmental, financial, reliability and reputational impacts. This section of the MD&A discusses risks that impacted financial performance in the year. Risks that impact non-financial organizational performance are discussed in the Risk and Capacity section of this Annual Report.

The impact of many financial risks associated with uncontrollable external influences on BC Hydro's net income is mitigated through the use of regulatory accounts. Regulatory accounts assist in matching costs and benefits for different generations of customers, to smooth the impact of large, non-recurring costs and to defer for future recovery in rates the differences between planned and actual costs or revenues that arise due to uncontrollable events. BC Hydro has a documented plan for the recovery of its regulatory accounts which it filed with the F15-F16 RRRA.

SIGNIFICANT FINANCIAL RISKS

The largest sources of variability in BC Hydro's financial performance are typically domestic and trade revenue and cost of energy. Both revenues and cost of energy are influenced by several elements, which generally fall into the following four categories:

- Generation available from BC Hydro-dispatched hydro plants;
- Domestic demand for electricity;
- Energy market prices; and,
- Deliveries from Electricity Purchase Agreement (EPA) contracts.

Neither a high nor a low value of any of these individual drivers is intrinsically positive or negative for BC Hydro's financial results. It is the specific combination of these drivers in any given year which has an impact.

While meeting domestic demand, environmental regulations and treaty obligations, BC Hydro attempts to operate the system to take maximum advantage of market energy prices – buying from the markets when prices are low and selling when prices are high. In doing so, BC Hydro attempts to optimize the combined effects of these elements and reduce the net cost of energy for our customers.

Generation Availability

The amount of generation available influences BC Hydro's financial results through both changing the amount of energy we have available to export (or need to import to meet domestic load) and through changing our ability to take advantage of short term market price variations. The amount of available generation is driven primarily by hydrology - the amount and timing of inflows into BC Hydro-dispatched plants. The range of historic inflows is significant, with over 15,000 GWh (or approximately 25 per cent of current domestic demand) separating the wettest years from the driest in the most recent 40 years of data in BC Hydro's records. To a less significant extent, the amount of available generation is also impacted by the availability of both BC Hydro and IPP generating assets and by BC Hydro's operation of the system.

The financial forecast in the Service Plan assumes that inflows into BC Hydro-dispatched plants will be the average of the most recent 40 years of data in BC Hydro's records. The final system inflow energy for fiscal 2014 was 5 per cent below this average, whereas the system inflow energy for fiscal 2013 was 9 per cent above average (with unusually high water conditions and some minor flooding impacts during fiscal 2013). In fiscal 2014, changes in the amount of available BC Hydro generation had a negative impact on net income before regulatory account transfers. The previous Domestic Revenues and Domestic Energy Costs discussions contain more information on the impact on fiscal 2014 financial performance.

Domestic Demand For Energy

Electricity demand is generally increasing as B.C.'s population increases. However, this demand can be variable for large industrial customers due to variability in export markets and world commodity prices. Weather is a significant driver of residential load, with colder years resulting in higher demand for electrical heating. The timing and ultimate impact of demand side management programs is also difficult to predict and can cause variations between expected and actual load. Both the amount of electricity used by BC Hydro's customers and the time at which it is used influence the amount and timing of BC Hydro's market energy purchases and sales. To the extent there is a mismatch between the amount of available generation and domestic demand BC Hydro will be either a net importer or net exporter of energy in a given year. However, even in high inflow years, BC Hydro may need to make some purchases during periods of the year when generation availability is low because of either water management requirements or maintenance outages (generally late fall, winter, and early spring). Similarly, even in low water years, electricity sales may be advantageous during certain periods either to minimize spill from large reservoirs or to take advantage of market price fluctuations. The value of all of these transactions is subject to market price risk.

In fiscal 2014, changes in domestic loads were positive for net income before regulatory account transfers. More information can be found in the discussion on Domestic Revenues.

Energy Market Prices

The cost of energy purchases, the value of trade energy sales and the trade opportunities available to Powerex all depend on energy market prices. The colder than average North American winter in fiscal 2014 resulted in a drawdown in natural gas storage to levels significantly below the 5 year range, resulting in an increase in gas prices and a knock-on effect on electricity prices. In fiscal 2014, Powerex was able to respond to market conditions which had a positive impact on net income before regulatory transfers. However, BC Hydro was required to be a net importer in fiscal 2014 because of lower than average inflows and generation outages required for capital projects. The higher market prices combined with the need to import energy had a negative impact on net income before regulatory transfers.

Deliveries From EPA Contracts

Energy delivered under EPA contracts has a different cost than both energy generated by BC Hydro and energy purchased or sold in energy markets. Therefore, as the proportion of EPA contract energy changes BC Hydro's average cost of energy changes. Greater than forecast thermal generation was required to meet "Reliability Must Run" standards on Vancouver Island in fiscal 2014. This contributed to a negative impact for financial results since the marginal price of EPA contract resources was greater than market prices.

Finance Charges

Interest expenses on borrowings are a significant component of Finance Charges. Variability in interest expenses on borrowings is influenced by both the volume of debt BC Hydro requires and the interest rate paid on that debt. A portion of BC Hydro's existing debt is subject to changes to interest rates ("variable rate debt") which results in volatility in interest costs. BC Hydro accepts this volatility in return for the savings obtained from normally lower short term rates.

As of March 31, 2014, approximately 26 per cent of existing debt had a maturity of one year or less and is recognized as variable rate debt. BC Hydro has steadily reduced its allocation of variable rate debt over the last few years in response to historically low long term interest rates and rising debt levels. The majority of BC Hydro's USD denominated debt is hedged with long term foreign exchange derivative contracts and as a result is not a significant risk variable.

The actual fiscal 2014 financial results compared to the Service Plan can be found in the previous Comparison with Service Plan discussion.

FUTURE OUTLOOK

The *Budget Transparency and Accountability Act* requires that BC Hydro file a Service Plan each year. BC Hydro's Service Plan filed in February 2014 forecast net income for fiscal 2015 at $582 million. This forecast is consistent with the 10 year plan announced by the Government in November 2013.

The Company's earnings can fluctuate significantly due to various non-controllable factors such as the level of water inflows, domestic sales load, market prices for electricity and natural gas, weather temperatures, interest rates and foreign exchange rates. The impact to net income of these non-controllable factors is largely mitigated through the use of regulatory accounts. The forecast for fiscal 2015 assumes average water inflows (100 per cent of average), domestic sales of 56,886 GWh, average market energy prices of U.S. $31.85/MWh, short-term interest rates of 1.28 per cent, a U.S. dollar exchange rate of U.S. $0.9547, an allowed return on equity of 11.84 per cent, and an approved rate increase of 9.0 per cent for fiscal 2015.

EARNINGS SENSITIVITY

The following table shows the effect on earnings of changes in some key variables. The analysis is based on business conditions and production volumes forecast for fiscal 2015. Each separate item in the sensitivity analysis assumes the others are held constant. While these sensitivities are applicable to the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or greater magnitude of changes.

The volatility between BC Hydro's plan and actual results are mostly mitigated through the use of BCUC-approved regulatory accounts.

Factor	Change	Approximate change in earnings before regulatory account transfers (in $ millions)	5 year high	5 year low	Fiscal 2014
Hydro generation[1]	1,000 GWh	30	52,114 GWh	39,303 GWh	45,306 GWh
Electricity trade margins	+/-10%	20	n/a	n/a	n/a
Interest rates	+/- 1%	50	1.30%[2]	0.45%[2]	1.27%[2]
Exchange rates (US/ CDN)	$0.01	5	$1.01[3]	$0.92[3]	$0.95[3]
Weather	1°C change in average temperature	20	1.0°C[4]	-0.7 °C[4]	-0.7°C[4]

[1] *Assumes change in hydro generation is offset by corresponding change in energy imports (i.e. increase in hydro generation is offset by decrease in energy imports).*
[2] *Interest rates are the average Canadian short-term interest rates (3-month Canadian Dollar Offered Rate).*
[3] *Exchange rates are the average US Dollar noon rates.*
[4] *Weather high and low numbers represents the variance in degrees Celsius from the normal temperatures over the winter months November to March from 2009/10 to 2013/14. (-0.7 degrees lower than normal to 1.0 degrees higher than normal – normal is the 10 year rolling average).*

MANAGEMENT REPORT

The consolidated financial statements of British Columbia Hydro and Power Authority (BC Hydro) are the responsibility of management and have been prepared in accordance with the financial reporting provisions prescribed by the Province of British Columbia pursuant to Section 23.1 of the *Budget Transparency and Accountability Act* and Section 9.1 of the *Financial Administration Act* (see Note 2(a)). The preparation of financial statements necessarily involves the use of estimates which have been made using careful judgment. In management's opinion, the consolidated financial statements have been properly prepared within the framework of the accounting policies summarized in the consolidated financial statements and incorporate, within reasonable limits of materiality, all information available at May 29, 2014. The consolidated financial statements have also been reviewed by the Audit & Finance Committee and approved by the Board of Directors. Financial information presented elsewhere in this Annual Report is consistent with that in the consolidated financial statements.

Management maintains systems of internal controls designed to provide reasonable assurance that assets are safeguarded and that reliable financial information is available on a timely basis. These systems include formal written policies and procedures, careful selection and training of qualified personnel and appropriate delegation of authority and segregation of responsibilities within the organization. An internal audit function independently evaluates the effectiveness of these internal controls on an ongoing basis and reports its findings to management and the Audit & Finance Committee.

The consolidated financial statements have been examined by independent external auditors. The external auditors' responsibility is to express their opinion on whether the consolidated financial statements, in all material respects, fairly present BC Hydro's financial position, comprehensive income and cash flows in accordance with financial reporting provisions prescribed by the Province of British Columbia pursuant to Section 23.1 of the *Budget Transparency and Accountability Act* and Section 9.1 of the *Financial Administration Act* (see Note 2(a)). The Auditors' Report, which follows, outlines the scope of their examination and their opinion.

The Board of Directors, through the Audit & Finance Committee, is responsible for ensuring that management fulfills its responsibility for financial reporting and internal controls. The Audit & Finance Committee, comprised of directors who are not employees, meets regularly with the external auditors, the internal auditors and management to satisfy itself that each group has properly discharged its responsibility to review the financial statements before recommending approval by the Board of Directors. The Audit & Finance Committee also recommends the appointment of external auditors to the Board of Directors. The internal and external auditors have full and open access to the Audit & Finance Committee, with and without the presence of management.

Charles Reid
President and Chief Executive Officer

Cheryl Yaremko
Executive VP Finance & Chief Financial Officer

Vancouver, Canada
May 29, 2014

INDEPENDENT AUDITORS' REPORT

The Minister of Energy and Mines and Minister Responsible for Core Review, Province of British Columbia and the Board of Directors of British Columbia Hydro and Power Authority:

We have audited the accompanying consolidated financial statements of British Columbia Hydro and Power Authority, which comprise the consolidated statement of financial position as at March 31, 2014, the consolidated statements of comprehensive income, changes in equity and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with the financial reporting provisions prescribed by the Province of British Columbia pursuant to Section 23.1 of the *Budget Transparency and Accountability Act* and Section 9.1 of the *Financial Administration Act* (see Note 2(a)), and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of British Columbia Hydro and Power Authority as at March 31, 2014 and its consolidated financial performance and its consolidated cash flows for the year then ended in accordance with the financial reporting provisions prescribed by the Province of British Columbia pursuant to Section 23.1 of the *Budget Transparency and Accountability Act* and Section 9.1 of the *Financial Administration Act* (see Note 2(a)).

KPMG LLP

Chartered Accountants

Vancouver, Canada

May 29, 2014

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

for the years ended March 31 (in millions)	2014	2013
Revenues		
Domestic	$ 4,319	$ 4,038
Trade	1,073	860
	5,392	4,898
Expenses		
Operating Expenses (Note 5)	4,245	3,849
Finance Charges (Note 6)	598	540
Net Income	549	509
OTHER COMPREHENSIVE INCOME (LOSS)		
Items Reclassified Subsequently to Net Income		
Effective portion of changes in fair value of derivatives designated as cash flow hedges	37	(5)
Reclassification to income on derivatives designated as cash flow hedges	(70)	(10)
Foreign currency translation gains	16	2
Other Comprehensive Loss	(17)	(13)
Total Comprehensive Income	$ 532	$ 496

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

as at March 31 (in millions)	2014	2013
ASSETS		
Current Assets		
Cash and cash equivalents (Note 8)	$ 107	$ 60
Restricted cash (Notes 8 and 15)	355	70
Accounts receivable and accrued revenue (Note 9)	718	651
Inventories (Note 10)	114	173
Prepaid expenses	211	201
Current portion of derivative financial instrument assets (Note 19)	96	83
	1,601	1,238
Non-Current Assets		
Property, plant and equipment (Note 11)	18,525	17,226
Intangible assets (Note 12)	501	438
Regulatory assets (Note 13)	4,928	4,741
Sinking funds (Note 14)	129	112
Derivative financial instrument assets (Note 19)	27	27
	24,110	22,544
	$ 25,711	$ 23,782
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities (Notes 15 and 20)	$ 1,886	$ 1,544
Current portion of long-term debt (Note 16)	4,087	3,288
Current portion of derivative financial instrument liabilities (Note 19)	76	172
	6,049	5,004
Non-Current Liabilities		
Long-term debt (Note 16)	11,610	10,846
Regulatory liabilities (Note 13)	229	307
Derivative financial instrument liabilities, long-term (Note 19)	55	94
Contributions in aid of construction	1,291	1,196
Post-employment benefits (Note 18)	1,173	1,396
Other long-term liabilities (Note 20)	1,439	1,439
	15,797	15,278
Shareholder's Equity		
Contributed surplus	60	60
Retained earnings	3,751	3,369
Accumulated other comprehensive income	54	71
	3,865	3,500
	$ 25,711	$ 23,782

Commitments and Contingencies (Note 21)

See accompanying Notes to Consolidated Financial Statements.

Approved on Behalf of the Board:

Steve Bellringer

Stephen Bellringer
Chair, Board of Directors

Tracey L. McVicar
Chair, Audit & Finance Committee

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(in millions)	Cumulative Translation Reserve	Unrealized Gains/(Losses) on Cash Flow Hedges	Total Accumulated Other Comprehensive Income	Contributed Surplus	Retained Earnings	Total
Balance, April 1, 2012	$ 15	$ 69	$ 84	$ 60	$ 3,075	$ 3,219
Payment to the Province	-	-	-	-	(215)	(215)
Comprehensive Income (Loss)	2	(15)	(13)	-	509	496
Balance, March 31, 2013	17	54	71	60	3,369	3,500
Payment to the Province	-	-	-	-	(167)	(167)
Comprehensive Income (Loss)	16	(33)	(17)	-	549	532
Balance, March 31, 2014	$ 33	$ 21	$ 54	$ 60	$ 3,751	$ 3,865

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

for the years ended March 31 (in millions)	2014	2013
Operating Activities		
Net income	$ 549	$ 509
Regulatory account transfers (Note 13)	(584)	(720)
Adjustments for non-cash items:		
Amortization of regulatory accounts (Note 13)	319	321
Amortization and depreciation expense	643	615
Unrealized gains on mark-to-market	(39)	(16)
Employee benefit plan expenses	94	30
Interest accrual	650	633
Other items	42	4
	1,674	1,376
Changes in:		
Restricted cash	(285)	(39)
Accounts receivable and accrued revenue	(36)	(82)
Prepaid expenses	(9)	(54)
Inventories	64	(30)
Accounts payable, accrued liabilities and other long-term liabilities	(78)	210
Contributions in aid of construction	132	128
	(212)	133
Interest paid	(647)	(621)
Cash provided by operating activities	815	888
Investing Activities		
Property, plant and equipment and intangible asset expenditures	(1,943)	(1,810)
Cash used in investing activities	(1,943)	(1,810)
Financing Activities		
Long-term debt:		
Issued	1,011	1,528
Retired	(706)	(200)
Receipt of revolving borrowings	8,409	6,061
Repayment of revolving borrowings	(7,224)	(6,172)
Payment to the Province (Note 17)	(215)	(230)
Settlement of derivative instruments	(84)	-
Other items	(16)	(17)
Cash provided by financing activities	1,175	970
Increase in cash and cash equivalents	47	48
Cash and cash equivalents, beginning of year	60	12
Cash and cash equivalents, end of year	$ 107	$ 60

See accompanying Notes to Consolidated Financial Statements.

NOTE 1: REPORTING ENTITY

British Columbia Hydro and Power Authority (BC Hydro) was established in 1962 as a Crown corporation of the Province of British Columbia (the Province) by enactment of the *Hydro and Power Authority Act*. As directed by the *Hydro and Power Authority Act*, BC Hydro's mandate is to generate, manufacture, conserve and supply power. BC Hydro owns and operates electric generation, transmission and distribution facilities in the province of British Columbia.

The consolidated financial statements of BC Hydro include the accounts of BC Hydro and its principal wholly-owned operating subsidiaries Powerex Corp. (Powerex), Powertech Labs Inc. (Powertech), and Columbia Hydro Constructors Ltd. (Columbia), (collectively with BC Hydro, "the Company") including BC Hydro's one third interest in the Waneta Dam and Generating Facility (Waneta). All intercompany transactions and balances are eliminated on consolidation.

The Company accounts for its one third interest in Waneta as a joint operation. The consolidated financial statements include the Company's proportionate share in Waneta, including its share of any liabilities and expenses incurred jointly with Teck Metals Ltd. and its revenue from the sale of the output in relation to Waneta.

NOTE 2: BASIS OF PRESENTATION

(a) Basis of Accounting

These consolidated financial statements have been prepared in accordance with the significant accounting policies as set out in Note 4. These policies have been established based on the financial reporting provisions prescribed by the Province pursuant to Section 23.1 of the *Budget Transparency and Accountability Act* (BTAA) and Section 9.1 of the *Financial Administration Act* (FAA). In accordance with the directive issued by the Province's Treasury Board, BC Hydro is to prepare these consolidated financial statements in accordance with the accounting principles of International Financial Reporting Standards (IFRS), combined with regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980 (ASC 980), *Regulated Operations* (collectively the "Prescribed Standards"). The application of ASC 980 results in BC Hydro recognizing in the statement of financial position the deferral and amortization of certain costs and recoveries that have been approved by the British Columbia Utilities Commission (BCUC) for inclusion in future customer rates. Such regulatory costs and recoveries would be included in the determination of comprehensive income unless recovered in rates in the year the amounts are incurred.

BC Hydro's accounting policies with respect to its regulatory accounts are disclosed in Note 4(a) and the impact of the application of ASC 980 on these consolidated financial statements is described in Note 13.

Certain amounts in the prior year's comparative figures have been reclassified to conform to the current year's presentation.

These consolidated financial statements were approved by the Board of Directors on May 29, 2014.

(b) Basis of Measurement

The consolidated financial statements have been prepared on the historical cost basis except for financial instruments that are accounted for according to the financial instrument categories as defined in Note 4(j) and the post employment benefits obligation as described in Note 4(n).

(c) Functional and Presentation Currency

The functional currency of BC Hydro and all of its subsidiaries, except for Powerex, is the Canadian dollar. Powerex's functional currency is the U.S. dollar. These consolidated financial statements are presented in Canadian dollars and financial information has been rounded to the nearest million.

(d) Key Assumptions and Significant Judgments

The preparation of financial statements in conformity with the Prescribed Standards requires management to make judgments, estimates and assumptions in respect of the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from those judgments, estimates, and assumptions.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized in the period in which the estimates are revised and in any future periods affected. Information about significant areas of judgment, estimates and assumptions in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements is as follows:

(i) Retirement Benefit Obligation

BC Hydro operates a defined benefit statutory pension plan for its employees which is accounted for in accordance with IAS 19, *Employee Benefits*. Actuarial valuations are based on key assumptions which include employee turnover, mortality rates, discount rates, earnings increases and expected rate of return on retirement plan assets. Judgment is exercised in determining these assumptions. The assumptions adopted are based on prior experience, market conditions and advice of plan actuaries. Future results are impacted by these assumptions including the accrued benefit obligation and current service cost. See Note 18 for significant benefit plan assumptions.

(ii) Provisions and Contingencies

Management is required to make judgments to assess if the criteria for recognition of provisions and contingencies are met, in accordance with IAS 37, *Provisions, Contingent Liabilities and Contingent Assets*. IAS 37 requires that a provision be recognized where there is a present obligation as a result of a past event, it is probable that transfer of economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Key judgments are whether a present obligation exists and the probability of an outflow being required to settle that obligation.

Key assumptions in measuring recorded provisions include the timing and amount of future payments and the discount rate applied in valuing the provision.

The Company is currently defending certain lawsuits where management must make judgments, estimates and assumptions about the final outcome, timing of trial activities and future costs as at the period end date. Management has obtained the advice of its external counsel in determining the likely outcome and estimating the expected costs associated with these lawsuits; however, the ultimate outcome or settlement costs may differ from management's estimates.

(iii) Financial Instruments

The Company enters into financial instrument arrangements which require management to make judgments to determine if such arrangements are derivative instruments in their entirety or contain embedded derivatives, including whether those embedded derivatives meet the criteria to be separated from their host contract, in accordance with IAS 39, *Financial Instruments: Recognition and Measurement*. Key judgments are whether certain non-financial items are readily convertible to cash, whether similar contracts are routinely settled net in cash or delivery of the underlying commodity taken and then resold within a short period, whether the value of a contract changes in response to a change in an underlying rate, price, index or other variable, and for embedded derivatives, whether the economic risks and characteristics are not closely related to the host contract and a separate instrument with the same terms would meet the definition of a derivative on a standalone basis.

Valuation techniques are used in measuring the fair value of financial instruments when active market quotes are not available. Valuation of the Company's financial instruments is based in part on forward prices which are volatile and therefore the actual realized value may differ from management's estimates.

(iv) Leases

The Company enters into long-term energy purchase agreements that may be considered to be, or contain a lease. In making this determination, judgment is required to determine whether the fulfillment of an arrangement is dependent on the use of a specific asset, and whether the arrangement conveys a right to use the asset. For those arrangements considered to be, or contain, an embedded lease, further judgment is required to determine whether to account for the agreement as either a finance or operating lease by assessing whether substantially all of the significant risks and rewards of ownership are transferred to the Company or remain with the counterparty to the agreement. The measurement of finance leases requires the estimate of the amount and timing of future cash flows and the determination of an appropriate discount rate.

NOTE 3: CHANGES IN ACCOUNTING POLICIES

Except for the changes noted below, the Company has consistently applied the accounting policies set out in Note 4 to all periods presented in these consolidated financial statements.

The Company has adopted the following new standards and amendments to standards with a date of initial application of April 1, 2013.

POST-EMPLOYMENT BENEFITS

The amended IAS 19, *Employee Benefits* replaced interest costs on the defined benefit obligation and the expected return on plan assets with a net interest cost based on the net defined benefit asset or liability. The net interest for the period is determined by applying the same discount rate used to measure the defined benefit obligation at the beginning of the annual period to the net defined benefit asset or liability at the beginning of the annual period, taking into account any changes in the net defined benefit asset or liability during the period as a result of current service costs, contributions and benefit payments. Previously, the Company determined expected return on plan assets based on their long term rate of expected return.

The Company applied the amended standard retrospectively to the prior periods presented. The impact of the adoption of the amended IAS 19 on the measurement of employee benefit costs was mitigated by the application of regulatory accounting in the current and prior periods presented.

FAIR VALUE MEASUREMENT

The Company applied IFRS 13, *Fair Value Measurement* prospectively as required by the transitional provisions. The standard provides a consistent definition of fair value and introduces consistent requirements for disclosures related to fair value measurement. There has been no significant measurement adjustments of items recorded at fair value as a result of the adoption of IFRS 13 in the current period.

Other standards adopted that have little or no impact on the consolidated financial statements include:

- IFRS 10, *Consolidated Financial Statements*
- IFRS 11, *Joint Arrangements*
- IFRS 12, *Disclosure of Interests in Other Entities*
- Amendments to IAS 1, *Presentation of Financial Statements*
- IAS 28, *Investments in Associates and Joint Ventures*
- IFRS 7, *Offsetting Financial Assets and Liabilities*

NOTE 4: SIGNIFICANT ACCOUNTING POLICIES

[a] Rate Regulation

BC Hydro is regulated by the BCUC and both entities are subject to directives and directions issued by the Province. BC Hydro operates under a cost of service regulation as prescribed by the BCUC. Orders in Council from the Province establish the basis for determining BC Hydro's equity for regulatory purposes, as well as its allowed return on equity and the annual Payment to the Province. Calculation of its revenue requirements and rates charged to customers are established through applications filed with and approved by the BCUC.

BC Hydro applies the principles of ASC 980, which differs from IFRS, to reflect the impacts of the rate-regulated environment in which BC Hydro operates (see Note 13). Generally, this results in the deferral and amortization of costs and recoveries to allow for adjustment of future customer rates. In the absence of rate-regulation, these amounts would otherwise be included in comprehensive income unless recovered in rates in the year the amounts are incurred. BC Hydro capitalizes as a regulatory asset all or part of an incurred cost that would otherwise be charged to expense or other comprehensive income if it is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes and the future rates and revenue approved by the BCUC will permit recovery of that incurred cost. Regulatory liabilities are recognized for certain gains or other reductions of net allowable costs for adjustment of future rates as determined by the BCUC.

These accounting policies support BC Hydro's rate regulation and regulatory accounts have been established through ongoing application to, and approval by, the BCUC. When a regulatory account has been or will be applied for, and, in management's estimate, acceptance of deferral treatment by the BCUC is considered probable, BC Hydro defers such costs in advance of a final decision of the BCUC. If the BCUC subsequently denies the application for regulatory treatment, the remaining deferred amount is recognized immediately in comprehensive income.

[b] Revenue

Domestic revenues comprise sales to customers within the province of British Columbia and sales of firm energy outside the province under long-term contracts that are reflected in the Company's domestic load requirements. Other sales outside the province are classified as trade.

Revenue is recognized at the time energy is delivered to the Company's customers, the amount of revenue can be measured reliably and collection is reasonably assured. Revenue is determined on the basis of billing cycles and also includes accruals for electricity deliveries not yet billed.

Energy trading contracts that meet the definition of a financial or non-financial derivative are accounted for at fair value whereby any realized gains and losses and unrealized changes in the fair value are recognized in trade revenues in the period the change occurred.

Energy trading and other contracts which do not meet the definition of a derivative are accounted for on an accrual basis whereby the realized gains and losses are recognized as revenue as the contracts are settled. Such contracts are considered to be settled when, for the sale of products, the significant risks and rewards of ownership transfer to the buyer, and for the sale of services, those services are rendered.

[c] Finance Income and Charges

Finance income comprises income earned on sinking fund investments held for the redemption of long-term debt, the expected return on defined benefit plan assets, foreign exchange gains and realized hedging instrument gains that are recognized in the statement of comprehensive income, excluding energy trading contracts.

Finance charges comprise interest expense on borrowings, accretion expense on provisions and other long-term liabilities, interest on defined benefit obligations, interest on finance lease liabilities, foreign exchange losses and realized hedging instrument losses that are recognized in the statement of comprehensive income. All borrowing costs are recognized using the effective interest rate method.

Finance costs exclude borrowing costs attributable to the construction of qualifying assets, which are assets that take more than six months to prepare for their intended use.

(d) Foreign Currency

Foreign currency transactions are translated into the respective functional currencies of BC Hydro and its subsidiaries, using the exchange rates prevailing at the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies at the reporting date are re-translated to the functional currency at the exchange rate in effect at that date. The foreign currency gains or losses on monetary items is the difference between the amortized cost in the functional currency at the beginning of the period, adjusted for effective interest and payments during the period, and the amortized cost in the foreign currency translated at the exchange rate at the end of the reporting period. Non-monetary items that are measured in terms of historical cost in a foreign currency are translated using the exchange rate at the date of the transaction.

For purposes of consolidation, the assets and liabilities of Powerex, whose functional currency is the U.S. dollar, are translated to Canadian dollars using the rate of exchange in effect at the reporting date. Revenue and expenses of Powerex are translated to Canadian dollars at exchange rates at the date of the transactions. Foreign currency differences resulting from translation of the accounts of Powerex are recognized directly in other comprehensive income and are accumulated in the cumulative translation reserve. Foreign exchange gains or losses arising from a monetary item receivable from or payable to Powerex, the settlement of which is neither planned nor likely in the foreseeable future and which in substance is considered to form part of a net investment in Powerex by BC Hydro, are recognized directly in other comprehensive income in the cumulative translation reserve.

(e) Property, Plant and Equipment

(i) Recognition and Measurement

Property, plant and equipment in service are measured at cost less accumulated depreciation and accumulated impairment losses.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials, direct labor and any other costs directly attributable to bringing the asset into service. The cost of dismantling and removing an item of property, plant and equipment and restoring the site on which it is located is estimated and capitalized only when, and to the extent that, the Company has a legal or constructive obligation to dismantle and remove such asset. Property, plant and equipment in service include the cost of plant and equipment financed by contributions in aid of construction. Borrowing costs that are directly attributable to the acquisition or construction of a qualifying asset are capitalized as part of the cost of the qualifying asset. Upon retirement or disposal, any gain or loss is recognized in the statement of comprehensive income.

The Company recognizes government grants when there is reasonable assurance that any conditions attached to the grant will be met and the grant will be received. Government grants related to assets are deducted from the carrying amount of the related asset and recognized in profit or loss over the life of the related asset.

Unfinished construction consists of the cost of property, plant and equipment that is under construction or not ready for service. Costs are transferred to property, plant and equipment in service when the constructed asset is capable of operation in a manner intended by management.

(ii) Subsequent Costs

The cost of replacing a component of an item of property, plant and equipment is recognized in the carrying amount of the item if it is probable that the future economic benefits embodied within the component will flow to the Company, and its cost can be measured reliably. The carrying amount of the replaced component is derecognized. The costs of property, plant and equipment maintenance are recognized in the statement of comprehensive income as incurred.

(iii) Depreciation

Property, plant and equipment in service are depreciated over the expected useful lives of the assets, using the straight-line method. When major components of an item of property, plant and equipment have different useful lives, they are accounted for as separate items of property, plant and equipment.

The expected useful lives, in years, of the Company's main classes of property, plant and equipment are:

Generation	15 - 100
Transmission	20 - 65
Distribution	20 - 60
Buildings	5 - 60
Equipment & Other	3 - 35

The expected useful lives and residual values of items of property, plant and equipment are reviewed annually.

Depreciation of an item of property, plant and equipment commences when the asset is available for use and ceases at the earlier of the date the asset is classified as held for sale and the date the asset is derecognized.

(f) Intangible Assets

Intangible assets are recorded at cost less accumulated amortization and accumulated impairment losses. Land rights associated with statutory rights of way acquired from the Province that have indefinite useful lives and are not subject to amortization. Intangible assets with finite useful lives are amortized over their expected useful lives on a straight line basis. These assets are tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset value may not be fully recoverable. The expected useful lives, in years, are as follows:

Software	2 - 10
Sundry	10 - 20

Amortization of intangible assets commences when the asset is available for use and ceases at the earlier of the date that the asset is classified as held for sale and the date that the asset is derecognized.

(g) Asset Impairment

(i) Financial Assets

Financial assets, other than those measured at fair value, are assessed at each reporting date to determine whether there is impairment. A financial asset is impaired if evidence indicates that a loss event has occurred after the initial recognition of the asset, and that the loss event had a negative effect on the estimated future cash flows of that asset that can be estimated reliably.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the asset's original effective interest rate. An impairment loss in respect of an available-for-sale financial asset is calculated by reference to its fair value.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in net income. Any cumulative loss in respect of an available-for-sale financial asset previously recognized in other comprehensive income and presented in unrealized gains/losses on available-for-sale financial assets in equity is transferred to net income.

An impairment loss is reversed if the reversal can be related to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost and available-for-sale financial assets that are debt securities, the reversal is recognized in net income.

(ii) Non-Financial Assets

The carrying amounts of the Company's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. For intangible assets that have indefinite useful lives or that are not yet available for use, the recoverable amount is estimated annually.

For the purpose of impairment testing, assets that cannot be tested individually are grouped together into the smallest group of identifiable assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit, or CGU"). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. All of BC Hydro's assets form one CGU for the purposes of testing for impairment.

An impairment loss is recognized if the carrying amount of an asset or CGU exceeds its estimated recoverable amount. Impairment losses are recognized in net income. Impairment losses recognized in respect of a CGU are allocated to reduce the carrying amounts of the assets in the CGU on a pro-rata basis.

Impairment losses recognized in prior periods are assessed at the reporting date for any indications that the loss has decreased or no longer exists. Impairment reversals are recognized immediately in net income when the recoverable amount of an asset increases above the impaired net book value, not to exceed the carrying amount that would have been determined (net of depreciation) had no impairment loss been recognized for the asset in prior years.

(h) Cash and Cash Equivalents

Cash and cash equivalents include unrestricted cash and units of a money market fund (short-term investments) that are redeemable on demand and are carried at amortized cost and fair value, respectively.

(i) Inventories

Inventories are comprised primarily of natural gas, materials and supplies. Inventories are valued at the lower of cost determined on a weighted average basis and net realizable value. The cost of inventories comprises all costs of purchase, costs of conversion and other directly attributable costs incurred in bringing the inventories to their present location and condition. Net realizable value is the estimated selling price in the ordinary course of business, less the estimated selling expenses.

(j) Financial Instruments

(i) Financial Instruments – Recognition and Measurement

All financial instruments are required to be measured at fair value on initial recognition of the instrument, except for certain related party transactions. Measurement in subsequent periods depends on which of the following categories the financial instrument has been classified as: fair value through profit or loss, available-for-sale, held-to-maturity, loans and receivables, or other financial liabilities as defined by the standard. Transaction costs are expensed as incurred for financial instruments classified or designated as fair value through profit or loss. For other financial instruments, transaction costs are included in the carrying amount. All regular-way purchases or sales of financial assets are accounted for on a settlement date basis.

Financial assets and financial liabilities classified as fair value through profit or loss are subsequently measured at fair value with changes in those fair values recognized in net income. Financial assets classified as available-for-sale are subsequently measured at fair value, with changes in those fair values recognized in other comprehensive income until realized. Financial assets classified as held-to-maturity, loans and receivables, and financial liabilities classified as other financial liabilities are subsequently measured at amortized cost using the effective interest method of amortization less any impairment. Derivatives, including embedded derivatives that are not closely related to the host contract and are separately accounted for are generally classified as fair value through profit or loss and recorded at fair value in the statement of financial position.

The following table presents the classification of financial instruments in the various categories:

Category	Financial Instruments
Financial assets and liabilities at fair value through profit or loss	Short-term investments Designated long-term debt Derivatives not in a hedging relationship
Held to Maturity	US dollar sinking funds
Loans and receivables	Cash Accounts receivable and other receivables
Other financial liabilities	Accounts payable and accrued liabilities Revolving borrowings Long-term debt (including current portion due in one year) Finance lease obligations and First Nations liabilities presented in other long-term liabilities

(ii) Fair Value

The fair value of financial instruments reflects changes in the level of commodity market prices, interest rates, foreign exchange rates and credit risk. Fair value is the amount of consideration that would be agreed upon in an arm's length transaction between knowledgeable willing parties who are under no compulsion to act.

Fair value amounts reflect management's best estimates considering various factors including closing exchange or over-the-counter quotations, estimates of future prices and foreign exchange rates, time value of money, counterparty and own credit risk, and volatility. The assumptions used in establishing fair value amounts could differ from actual prices and the impact of such variations could be material. In certain circumstances, Powerex uses valuation inputs that are not based on observable market data and internally developed valuation models which are based on models and techniques generally recognized as standard within the energy industry.

(iii) Inception Gains and Losses

In some instances, a difference may arise between the fair value of a financial instrument at initial recognition, as defined by its transaction price, and the fair value calculated by a valuation technique or model. In these limited circumstances, the unrealized gain or loss at inception is recognized in income only if the gain or loss on the instrument is evidenced by a quoted market price in an active market or if the valuation technique or model uses only observable market data as inputs. Where these criteria are not met, the unrealized gain or loss at inception is deferred and amortized into income over the period until all data inputs become observable in the market, or, when data inputs are not expected to become observable in the future, over the full term of the underlying financial instrument. Additional information on deferred inception gains and losses is disclosed in Note 19, Financial Instruments.

(iv) Derivative Financial Instruments

The Company uses derivative financial instruments to manage interest rate and foreign exchange risks related to debt and to manage risks related to electricity and natural gas commodity transactions.

Interest rate and foreign exchange related derivative instruments that are not designated as hedges, are recorded using the mark-to-market method of accounting whereby instruments are recorded at fair value as either an asset or liability with changes in fair value recognized in net income. For liability management activities, the related gains or losses are included in finance charges. For foreign currency exchange risk associated with electricity and natural gas commodity transactions, the related gains or losses are included in domestic revenues. The Company's policy is to not utilize interest rate and foreign exchange related derivative financial instruments for speculative purposes.

Derivative financial instruments are also used by Powerex to manage economic exposure to market risks relating to commodity prices. Derivatives used for energy trading activities that are not designated as hedges are recorded using the market-to-market method of accounting whereby instruments are recorded at fair value as either an asset or liability with changes in fair value recognized in net income. Gains or losses are included in trade revenues.

(v) Hedges

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for unrealized gains or losses attributable to the hedged risk and recognized in net income. Changes in the fair value of the hedged item attributed to the hedged risk, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging derivative, which is also recorded in net income. When hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to net income over the remaining term of the original hedging relationship, using the effective interest method of amortization.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income. The ineffective portion is recognized in net income. The amounts recognized in accumulated other comprehensive income are reclassified to net income in the periods in which net income is affected by the variability in the cash flows of the hedged item. When hedge accounting is discontinued the cumulative gain or loss previously recognized in accumulated other comprehensive income remains there until the forecasted transaction occurs. When the hedged item is a non-financial asset or liability, the amount recognized in accumulated other comprehensive income is transferred to the carrying amount of the asset or liability when it is recognized. In other cases the amount recognized in accumulated other comprehensive income is transferred to net income in the same period that the hedged item affects net income.

Hedge accounting is discontinued prospectively when the derivative no longer qualifies as an effective hedge, the hedging relationship is discontinued, or the derivative is terminated or sold, or upon the sale or early termination of the hedged item.

(k) Investments Held in Sinking Funds

Investments held in sinking funds are held as individual portfolios and are classified as held to maturity. Securities included in an individual portfolio are recorded at cost, adjusted by amortization of any discounts or premiums arising on purchase, on a yield basis over the estimated term to settlement of the security. Realized gains and losses are included in sinking fund income.

(l) Deferred Revenue – Skagit River Agreement

Deferred revenue consists principally of amounts received under the agreement relating to the Skagit River, Ross Lake and the Seven Mile Reservoir on the Pend d'Oreille River (collectively, "the Skagit River Agreement").

Under the Skagit River Agreement, the Company has committed to deliver a predetermined amount of electricity each year to the City of Seattle for an 80-year period ending in fiscal 2066 in return for two annual payments of approximately US$22 million per year for a 35 year period ending in 2021 and US$100,000 (adjusted for inflation) per year for the 80-year period ending in 2066. The amounts received under the agreement are deferred and included in income on an annuity basis over the electricity delivery period ending in fiscal 2066.

(m) Contributions in Aid of Construction

Contributions in aid of construction are amounts paid by certain customers toward the cost of property, plant and equipment required for the extension of services to supply electricity. These amounts are recognized into revenue over the expected useful life of the related assets, as the associated contracts do not have a finite period over which service is provided.

(n) Post-Employment Benefits

The cost of pensions and other post-employment benefits earned by employees is actuarially determined using the projected accrued benefit method prorated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. The net interest for the period is determined by applying the same market discount rate used to measure the defined benefit obligation at the beginning of the annual period to the net defined benefit asset or liability at the beginning of the annual period, taking into account any changes in the net defined benefit asset or liability during the period as a result of current service costs, contributions and benefit payments. The market discount rate is determined based on the market interest rate at the end of the year on high-quality corporate debt instruments that match the timing and amount of expected benefit payments.

Past service costs arising from plan amendments and curtailments are recognized in net income immediately. A plan curtailment will result if the Company has demonstrably committed to a significant reduction in the expected future service of active employees or a significant element of future service by active employees no longer qualifies for benefits. A curtailment is recognized when the event giving rise to the curtailment occurs.

The expected return on plan assets and the interest cost on the defined benefit plan liabilities arising from the passage of time are included in finance income and finance costs, respectively. The Company recognizes actuarial gains and losses immediately in other comprehensive income. The amount recognized in other comprehensive income is subsequently transferred to a regulatory asset account for inclusion in future rates.

(o) Provisions

A provision is recognized if the Company has a present legal or constructive obligation as a result of a past event, it is probable that an outflow of economic benefits will be required to settle the obligation and a reliable estimate of the obligation can be determined. For obligations of a long-term nature, provisions are measured at their present value by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability except in cases where future cash flows have been adjusted for risk.

Decommissioning Obligations

Decommissioning obligations are legal and constructive obligations associated with the retirement of long-lived assets. A liability is recorded at the present value of the estimated future costs based on management's best estimate. When a liability is initially recorded, the Company capitalizes the costs by increasing the carrying value of the asset. The increase in net present value of the provision for the expected cost is included in finance costs as accretion (interest) expense. Adjustments to the provision made for changes in timing, amount of cash flow and discount rates are capitalized and amortized over the useful life of the associated asset. Actual costs incurred upon settlement of a decommissioning obligation are charged against the related liability. Any difference between the actual costs incurred upon settlement of the decommissioning obligation and the recorded liability is recognized in net income at that time.

Environmental Expenditures and Liabilities

Environmental expenditures are expensed as part of operating activities, unless they constitute an asset improvement or act to mitigate or prevent possible future contamination, in which case the expenditures are capitalized and amortized to income. Environmental liabilities arising from a past event are accrued when it is probable that a present legal or constructive obligation will require the Company to incur environmental expenditures.

Legal

The Company recognizes legal claims as a provision when it is probable that the claim will be settled against the Company and the amount of the settlement can be reasonably measured. Management obtains the advice of its external counsel in determining the likely outcome and estimating the expected costs associated with lawsuits. Further information regarding lawsuits in progress, that have not been recognized, is disclosed in Note 21, Commitments and Contingencies.

(p) Leases

Embedded Leases

The Company may enter into an arrangement that does not take the legal form of a lease but conveys a right to use an asset in return for a payment or series of payments. Arrangements in which a party conveys a right to the Company to use an asset may in substance be, or contain, a lease that should be accounted for as either a finance or operating lease. Determining whether an arrangement is, or contains, a lease requires an assessment of whether fulfilment of the arrangement is dependent on the use of a specific asset; and whether the arrangement conveys a right to use the asset. The right to use an asset is conveyed if the right to operate or control physical access to the underlying asset is provided or if the Company consumes substantially all of the output of the asset and the price paid for the output is neither contractually fixed per unit of output nor equal to the current market price.

Finance Leases

Leases where substantially all of the benefits and risk of ownership rest with the Company are accounted for as finance leases. Finance leases are recognized as assets and liabilities at the lower of the fair value of the asset and the present value of the minimum lease payments at the date of acquisition. Finance costs represent the difference between the total leasing commitments and the fair value of the assets acquired. Finance costs are charged to net income over the term of the lease at interest rates applicable to the lease on the remaining balance of the obligations. Assets under finance leases are depreciated on the same basis as property, plant and equipment or over the term of the relevant lease, whichever is shorter.

Operating Leases

Leases where substantially all of the benefits and risk of ownership remain with the lessor are accounted for as operating leases. Rental payments under operating leases are expensed to net income on a straight-line basis over the term of the relevant lease. Benefits received and receivable as an incentive to enter into an operating lease are recognized as an integral part of the total lease expense and are recorded on a straight-line basis over the term of the lease.

(q) Taxes

The Company pays local government taxes and grants in lieu to municipalities and regional districts. As a Crown corporation, the Company is exempt from Canadian federal and provincial income taxes.

(r) Jointly Controlled Operations

The Company has joint ownership and control over certain assets with third parties. A jointly controlled operation exists when there is a joint ownership and control of one or more assets to obtain benefits for the joint operators. The parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, related to the arrangement. Each joint operator takes a share of the output from the assets for its own exclusive use. These consolidated financial statements include the Company's share of the jointly controlled assets. The Company also records its share of any liabilities and expenses incurred jointly with third parties and any revenue from the sale or use of its share of the output in relation to the assets.

(s) New Standards and Interpretations Not Yet Adopted

A number of new standards, and amendments to standards and interpretations, are not yet effective for the year ended March 31, 2014, and have not been applied in preparing these consolidated financial statements. In particular, the following new and amended standards become effective for the Company's annual periods beginning on or after the dates noted below:

- IFRS 9, *Financial Instruments* (tentatively effective April 1, 2018)
- Amendments to IFRS 10, *Consolidated Financial Statements* (effective April 1, 2014)
- Amendments to IFRS 12, *Disclosure of Interests in Other Entities* (effective April 1, 2014)
- Amendments to IAS 19, *Employee Benefits* (effective April 1, 2015)
- Amendments to IAS 27, *Consolidated and Separate Financial Statements* (effective April 1, 2014)
- Amendments to IAS 32, *Financial Instruments: Presentation* (April 1, 2014)
- Amendments to IAS 36, *Impairment of Assets* (effective April 1, 2014)
- Amendments to IAS 39, *Financial Instruments: Recognition and Measurement* (effective April 1, 2014)
- IFRIC 21, *Levies* (effective April 1, 2014)

The Company does not have any plans to early adopt any of the new or amended standards. It is anticipated that the standards effective for the Company's 2015 fiscal year will not have a material effect on the consolidated financial statements.

IFRS 14, *Regulatory Deferral Accounts*, effective for fiscal years beginning on or after January 1, 2016, has been issued; however, the Company currently does not intend to adopt IFRS 14 as it has adopted the Prescribed Standards, not IFRS, and accounts for its regulatory accounts in accordance with ASC 980.

NOTE 5: OPERATING EXPENSES

(in millions)	2014	2013
Electricity and gas purchases	$ 1,607	$ 1,291
Water rentals	361	352
Transmission charges	178	163
Personnel expenses	538	527
Materials and external services	579	606
Amortization and depreciation (Note 7)	995	953
Grants and taxes	203	196
Capitalized costs	(244)	(259)
Other costs, net of recoveries	28	20
Total	$ 4,245	$ 3,849

NOTE 6: FINANCE CHARGES

(in millions)	2014	2013
Interest on long-term debt	$ 731	$ 647
Interest on finance lease liabilities	46	27
Net interest expense on net defined benefit liability	14	14
Less: capitalized interest	(106)	(73)
Total finance costs	685	615
Other recoveries	(87)	(75)
Total	$ 598	$ 540

Capitalized interest presented in the table above is after regulatory transfers. Actual interest capitalized to property, plant and equipment and intangible assets before regulatory transfers was $89 million (2013 - $68 million). The effective capitalization rate used to determine the amount of borrowing costs eligible for capitalization was 4.3 per cent (2013 - 4.7 per cent).

NOTE 7: AMORTIZATION AND DEPRECIATION

(in millions)	2014	2013
Depreciation of property, plant and equipment	$ 581	$ 556
Amortization of intangible assets	62	59
Amortization of regulatory account assets	352	338
Total	$ 995	$ 953

NOTE 8: CASH AND CASH EQUIVALENTS AND RESTRICTED CASH

CASH AND CASH EQUIVALENTS

(in millions)		2014		2013
Cash	$	74	$	38
Short-term investments		33		22
Total	$	107	$	60

RESTRICTED CASH

(in millions)		2014		2013
Funds held in trust (Note 15)	$	302	$	-
Other		53		70
Total	$	355	$	70

Other restricted cash represents cash balances which the Company does not have immediate access to as they have been pledged to counterparties as security for investments or trade obligations. These balances are available to the Company only upon liquidation of the investments or settlement of the trade obligations they have been pledged as security for.

NOTE 9: ACCOUNTS RECEIVABLE AND ACCRUED REVENUE

(in millions)		2014		2013
Accounts receivable	$	512	$	458
Accrued revenue		92	$	95
Other		114		98
Total	$	718	$	651

Accrued revenue represents revenue for electricity delivered and not yet billed.

NOTE 10: INVENTORIES

(in millions)		2014		2013
Materials and supplies	$	111	$	108
Natural gas in storage		3		65
Total	$	114	$	173

During the year ended March 31, 2014, an impairment of $3 million (2013 – impairment reversal of $20 million) was included in cost of energy to adjust the recorded value of natural gas in storage as a result of a decrease in market prices. As at March 31, 2014, $2 million (March 31, 2013 - $41 million) of the value of natural gas in storage was valued at net realizable value.

Inventories recognized as an expense during the year amounted to $106 million (2013 - $32 million).

NOTE 11: PROPERTY, PLANT AND EQUIPMENT

(in millions)	Generation	Transmission	Distribution	Land & Buildings	Equipment & Other	Unfinished Construction	Total
Cost							
Balance at March 31, 2012	$ 5,970	$ 3,714	$ 4,302	$ 407	$ 490	$ 1,804	$ 16,687
Net additions	289	400	536	45	98	478	1,846
Disposals and retirements	(8)	(11)	(95)	(11)	(11)	(13)	(149)
Balance at March 31, 2013	6,251	4,103	4,743	441	577	2,269	18,384
Net additions	269	462	338	65	96	681	1,911
Disposals and retirements	(4)	(13)	(24)	(2)	(12)	(10)	(65)
Balance at March 31, 2014	$ 6,516	$ 4,552	$ 5,057	$ 504	$ 661	$ 2,940	$ 20,230
Accumulated Depreciation							
Balance at March 31, 2012	$ (285)	$ (139)	$ (182)	$ (28)	$ (62)	$ -	$ (696)
Depreciation expense	(178)	(138)	(173)	(16)	(59)	-	(564)
Disposals and retirements	4	7	72	11	8	-	102
Balance at March 31, 2013	(459)	(270)	(283)	(33)	(113)	-	(1,158)
Depreciation expense	(188)	(146)	(156)	(18)	(62)	-	(570)
Disposals and retirements	2	5	6	-	10	-	23
Balance at March 31, 2014	$ (645)	$ (411)	$ (433)	$ (51)	$ (165)	$ -	$ (1,705)
Net carrying amounts							
At March 31, 2013	$ 5,792	$ 3,833	$ 4,460	$ 408	$ 464	$ 2,269	$ 17,226
At March 31, 2014	$ 5,871	$ 4,141	$ 4,624	$ 453	$ 496	$ 2,940	$ 18,525

(i) As at March 31, 2014, the Company has included its one-third interest in Waneta with a net book value of $755 million (2013 - $777 million) in Generation assets. Depreciation expense on the Waneta asset for the year ended March 31, 2014 was $22 million (2013 - $22 million).

(ii) Included within Distribution assets are the Company's portion of utility poles with a net book value of $781 million (2013 - $734 million) that are jointly owned with a third party. Depreciation expense on jointly owned utility poles for the year ended March 31, 2014 was $20 million (2013 - $19 million).

(iii) The Company received government grants from the Columbia River Treaty related to three dams built by the Company in the mid-1960s to regulate the flow of the Columbia River. The grants were made to assist in financing the construction of the dams. The grants were deducted from the carrying amount of the related dams. In addition, during fiscal 2014, the Company received government grants of $94 million (2013 - $23 million) for the construction of a new transmission line and has deducted the grants received from the cost of the asset.

(iv) The Company has contractual commitments to spend $1,874 million on major property, plant and equipment projects (individual projects greater than $50 million) as at March 31, 2014.

LEASED ASSETS

Property, plant and equipment under finance leases of $388 million (2013 - $388 million), net of accumulated amortization of $159 million (2013 - $146 million), are included in the total amount of property, plant and equipment above.

NOTE 12: INTANGIBLE ASSETS

(in millions)	Land Rights	Internally Developed Software	Purchased Software	Other	Work in Progress	Total
Cost						
Balance at March 31, 2012	$ 177	$ 32	$ 223	$ 11	$ 31	$ 474
Net additions	5	16	66	-	(4)	83
Retirements	-	-	(9)	-	-	(9)
Balance at March 31, 2013	182	48	280	11	27	548
Net additions	1	37	68	-	19	125
Retirements	-	-	(14)	-	-	(14)
Balance at March 31, 2014	$ 183	$ 85	$ 334	$ 11	$ 46	$ 659
Accumulated Amortization						
Balance at March 31, 2012	$ -	$ (3)	$ (56)	$ (3)	$ -	$ (62)
Amortization expense	-	(6)	(49)	(2)	-	(57)
Retirements	-	-	9	-	-	9
Balance at March 31, 2013	-	(9)	(96)	(5)	-	(110)
Amortization expense	-	(12)	(47)	(3)	-	(62)
Retirements	-	-	14	-	-	14
Balance at March 31, 2014	$ -	$ (21)	$ (129)	$ (8)	$ -	$ (158)
Net carrying amounts						
At March 31, 2013	$ 182	$ 39	$ 184	$ 6	$ 27	$ 438
At March 31, 2014	$ 183	$ 64	$ 205	$ 3	$ 46	$ 501

Land rights consist primarily of statutory rights of way acquired from the Province in perpetuity. These land rights have indefinite useful lives and are not subject to amortization. These land rights are tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset value may not be recoverable.

NOTE 13: RATE REGULATION

REGULATORY ACCOUNTS

The following regulatory assets and liabilities have been established through rate regulation. In the absence of rate regulation, these amounts would be reflected in comprehensive income unless the Company sought recovery through rates in the year in which they are incurred. For the year ended March 31, 2014, the impact of regulatory accounting has resulted in a net increase to total comprehensive income of $265 million (2013 - $399 million) which is comprised of an increase to net income of $557 million (2013 - $208 million) and a decrease to other comprehensive income of $292 million (2013 – $191 million increase). For each regulatory account, the amount reflected in the Net Change column in the following regulatory tables represents the impact on comprehensive income for the applicable year, unless otherwise recovered through rates. Under rate regulated accounting, a net decrease in a regulatory asset or a net increase in a regulatory liability results in a decrease to comprehensive income.

(in millions)	*April 1 2013*	*Addition (Reduction)*	*Amortization*	*Net Change*	*March 31 2014*
Regulatory Assets					
Heritage Deferral Account	$ 70	$ 53	$ (18)	$ 35	$ 105
Non-Heritage Deferral Account	467	15	(120)	(105)	362
Trade Income Deferral Account	190	183	(49)	134	324
Demand-Side Management Programs	733	118	(63)	55	788
First Nation Negotiations, Litigation & Settlement Costs	553	42	(6)	36	589
Non-Current Pension Cost	544	(247)	(17)	(264)	280
Site C	258	80	-	80	338
CIA Amortization Variance	75	6	-	6	81
Environmental Provisions	367	24	(8)	16	383
Smart Metering and Infrastructure	192	85	-	85	277
Finance Charges	1	(1)	-	(1)	-
IFRS Pension & Other Post-Employment Benefits	723	-	(35)	(35)	688
IFRS Property, Plant and Equipment	447	179	(9)	170	617
Other Regulatory Accounts	121	2	(27)	(25)	96
Total Regulatory Assets	4,741	539	(352)	187	4,928
Regulatory Liabilities					
Future Removal and Site Restoration Costs	88	-	(32)	(32)	56
Rate Smoothing	111	(111)	-	(111)	-
Foreign Exchange Gains and Losses	100	(10)	(1)	(11)	89
Finance Charges	-	79	-	79	79
Other Regulatory Accounts	8	(3)	-	(3)	5
Total Regulatory Liabilities	307	(45)	(33)	(78)	229
Net Regulatory Asset	$ 4,434	$ 584	$ (319)	$ 265	$ 4,699

(in millions)	*April 1 2012*	*Addition (Reduction)*	*Amortization*	*Net Change*	*March 31 2013*
Regulatory Assets					
Heritage Deferral Account	$ 244	$ (118)	$ (56)	$ (174)	$ 70
Non-Heritage Deferral Account	429	122	(84)	38	467
Trade Income Deferral Account	205	25	(40)	(15)	190
Demand-Side Management Programs	638	148	(53)	95	733
First Nation Negotiations, Litigation & Settlement Costs	543	17	(7)	10	553
Non-Current Pension Cost	377	184	(17)	167	544
Site C	181	77	-	77	258
CIA Amortization Variance	68	7	-	7	75
Environmental Provisions	322	53	(8)	45	367
Smart Metering and Infrastructure	92	100	-	100	192
Finance Charges	49	(48)	-	(48)	1
IFRS Pension & Other Post-Employment Benefits	762	-	(39)	(39)	723
IFRS Property, Plant and Equipment	254	197	(4)	193	447
Other Regulatory Accounts	150	1	(30)	(29)	121
Total Regulatory Assets	4,314	765	(338)	427	4,741
Regulatory Liabilities					
Future Removal and Site Restoration Costs	104	-	(16)	(16)	88
Rate Smoothing	70	41	-	41	111
Foreign Exchange Gains and Losses	103	(2)	(1)	(3)	100
Other Regulatory Accounts	2	6	-	6	8
Total Regulatory Liabilities	279	45	(17)	28	307
Net Regulatory Asset	$ 4,035	$ 720	$ (321)	$ 399	$ 4,434

RATE REGULATION

During April 2013, the BCUC issued the Generic Cost of Capital (GCOC) decision which resulted in a reduction in the Benchmark Utility Return on Equity from 9.5 per cent to 8.75 per cent which would result in a decrease to the BC Hydro allowed rate of return (ROE) for fiscal 2014 from 11.84 per cent to 10.62 per cent. On March 6, 2014, the Province issued Direction No. 6 to the BCUC which resulted in the fiscal 2014 ROE effectively remaining at 11.84 per cent, rather than being reduced as it otherwise would have been to reflect the GCOC decision. Direction No. 6 also approved the Company's fiscal 2014 Demand Side Management (DSM) expenditures and, in addition, set the general rate increases for fiscal 2015 and fiscal 2016 at 9 per cent and 6 per cent, respectively.

On October 4, 2013, the Company's subsidiary, Powerex, received approval by the Federal Energy Regulatory Commission (FERC) for a settlement agreement with parties involved in the various ongoing legal claims in California to resolve all outstanding claims and litigation filed against it arising from events and transactions in the California power market during the 2000 and 2001 period (see Note 15). This was accounted for in the first quarter of fiscal 2014 which resulted in an expense of $214 million. On March 6, 2014, the Province issued Direction No. 7 to the BCUC which contained a provision that requires the BCUC to allow the Powerex net loss for fiscal 2014 only to be deferred to the Trade Income Deferral Account (TIDA).

HERITAGE DEFERRAL ACCOUNT (HDA)

Under a Special Direction issued by the Province, the BCUC was directed to authorize the Company to establish the HDA. This account is intended to mitigate the impact of certain variances between the forecasted costs in a revenue requirements application and actual costs of service associated with the Company's hydroelectric and thermal generating facilities by adjustment of net income. These deferred variances are recovered in rates through the rate rider.

NON-HERITAGE DEFERRAL ACCOUNT (NHDA)

Under a Special Direction issued by the Province, the BCUC approved the establishment of the NHDA, which is intended to mitigate the impact of certain cost variances between the forecasted costs in a revenue requirements application and actual costs related to energy acquisition and maintenance of the Company's distribution assets by adjustment of net income. These deferred variances are recovered in rates through the rate rider.

TRADE INCOME DEFERRAL ACCOUNT

Established under a Special Directive issued by the Province, this account is intended to mitigate the uncertainty associated with forecasting the net income of the Company's trade activities. The impact is to defer the difference between the Trade Income forecast in the revenue requirements application and actual Trade Income. These deferred variances are recovered in rates through the rate rider.

In May 2012, the Province amended the Heritage Special Direction No. 2 to change the definition of Trade Income and remove the $200 million cap. Trade Income is now defined as the greater of (a) the amount that is equal to BC Hydro's consolidated net income, less BC Hydro's non-consolidated net income, less the net income of the BC Hydro's subsidiaries except Powerex, less the amount that BC Hydro's consolidated net income changes due to foreign currency translation gains and losses on intercompany balances between BC Hydro and Powerex; and (b) zero. The difference between the Trade Income forecast and actual Trade Income is deferred except for amounts arising from a net loss in Trade Income. The removal of the $200 million cap on Powerex income allows ratepayers to benefit from all of Powerex's income.

On March 6, 2014, the Province issued Direction No. 7 to the BCUC which contained a provision that requires the BCUC to remove the "floor" of $nil in the definition of Trade income for fiscal 2014 only. As a result, Powerex's net loss for fiscal 2014 was deferred to the TIDA.

DEMAND-SIDE MANAGEMENT ACTIVITIES (DSM)

Amounts incurred for DSM are deferred and amortized on a straight-line basis over the anticipated 15 year period of benefit of the program. DSM programs are designed to reduce the energy requirements on the Company's system. DSM costs include materials, direct labour and applicable portions of support costs, equipment costs, and incentives, the majority of which are not eligible for capitalization. Costs relating to identifiable tangible assets that meet the capitalization criteria are recorded as property, plant and equipment.

FIRST NATION NEGOTIATIONS, LITIGATION AND SETTLEMENT COSTS

The First Nations Negotiations, Litigation and Settlement Costs consist primarily of settlement costs related to agreements reached with various First Nations groups. These agreements address settlements related to the construction and operation of the Company's existing facilities and provide compensation associated with past, present and future impacts. Provisions for and costs incurred with respect to First Nation negotiations, litigation and settlements are deferred and costs incurred are amortized on a straight-line basis over a period of 10 years.

Costs relating to identifiable tangible assets that meet the capitalization criteria are recorded as property, plant and equipment.

NON-CURRENT SERVICE PENSION COST

Variances that arise between forecast and actual non-current pension and other post employment benefit costs are deferred. These variances are recovered over the average remaining service life of the employee group. In the absence of rate regulation and the application of ASC 980, these cost variances would be included in operating results, which would have resulted in a $45 million decrease in net income for the year (2013 - $7 million increase).

In addition, actuarial gains and losses related to post employment benefit plans are also deferred. In the absence of rate regulation, these actuarial gains and losses would be included in other comprehensive income in the year in which they are incurred, which would have resulted in a $292 million increase in other comprehensive income (2013 - $191 million decrease). The net impact of the deferral of the non-current service pension costs variances and the actuarial gains is a net gain of $247 million (2013 - $184 million net loss).

SITE C

Site C expenditures incurred in fiscal 2007 through fiscal 2014 have been deferred.

CONTRIBUTIONS IN AID OF CONSTRUCTION (CIA) AMORTIZATION VARIANCE

This account captures the difference in revenue requirement impacts of the 45 year amortization period the Company uses as per a depreciation study and the 25 year amortization period determined by the BCUC.

ENVIRONMENTAL PROVISIONS

A liability provision and offsetting regulatory asset has been established for environmental compliance and remediation arising from the costs that will likely be incurred to comply with the Federal Polychlorinated Biphenyl (PCB) Regulations enacted under the *Canadian Environmental Protection Act*, the Asbestos requirements of the Occupational Health and Safety Regulations under the jurisdiction of WorkSafe BC and the remediation of environmental contamination at a property occupied by a predecessor company. The account is amortized based on actual expenditures incurred during the year.

SMART METERING AND INFRASTRUCTURE (SMI)

Operating costs incurred by the Company with respect to the SMI program are being deferred. Costs relating to identifiable tangible and intangible assets that meet the capitalization criteria are being recorded as property, plant and equipment or intangible assets respectively. The SMI net operating costs, amortization of capital assets, and finance charges have been deferred. The account balance will be amortized over 15 years starting in fiscal 2015.

FINANCE CHARGES

This account is intended to mitigate the impact of certain variances that arise between the forecasted costs in a revenue requirements application and actual finance charges incurred. Variances incurred during the current test period are recovered over the next test period. A test period refers to the period covered by a revenue requirements application filing (the current test period is fiscal 2015 and fiscal 2016).

IFRS PENSION & OTHER POST-EMPLOYMENT BENEFITS

Unamortized experience gains and losses on the pension and other post-employment benefit plans recognized at the time of transition to the Prescribed Standards were deferred to this regulatory account to allow for recovery in future rates. The account balance is amortized over the expected average remaining service life of the employees.

IFRS PROPERTY, PLANT & EQUIPMENT

This account includes the fiscal 2012 incremental earnings impacts due to the application of the accounting principles of IFRS to Property, Plant & Equipment to the comparative fiscal year for the adoption of the Prescribed Standards. In addition, the account includes an annual deferral of overhead costs, ineligible for capitalization under the accounting principles of IFRS, equal to the fiscal 2012 overhead deferral amount less a ten year phase-in adjustment. The annual deferred amounts are amortized over 40 years beginning the year following the deferral of the expenditures.

FUTURE REMOVAL AND SITE RESTORATION COSTS

This account was established by a one-time transfer of $251 million from retained earnings for liabilities previously recorded in excess of amounts required as decommissioning obligations. The costs of dismantling and disposal of property, plant and equipment will be applied to this regulatory liability if they do not otherwise relate to an asset retirement obligation.

RATE SMOOTHING

The Rate Smoothing regulatory account was established in order to smooth out annual rate increases applied for in the Amended F2012-F2014 Revenue Requirements Application. The balance was fully drawn down by the end of fiscal 2014.

FOREIGN EXCHANGE GAINS AND LOSSES

Foreign exchange gains and losses from the translation of specified foreign currency financial instruments are deferred. The account balance is amortized using the straight-line pool method over the weighted average life of the related debt.

OTHER REGULATORY ACCOUNTS

Other regulatory asset accounts with individual balances less than $40 million include the following: Arrow Water Systems, Capital Project Investigation Costs, Home Purchase Option Plan, Return on Equity (ROE) Adjustment, Waneta Rate Smoothing, and Asbestos Remediation.

Other regulatory liability accounts with individual balances less than $10 million include the following: Amortization of Capital Additions and Storm Damage.

NOTE 14: INVESTMENTS HELD IN SINKING FUNDS

Investments held in sinking funds are held by the Trustee (the Minister of Finance for the Province) for the redemption of long-term debt. The sinking fund balances at the statement of financial position date are accounted for as held to maturity, and include the following investments:

($ in millions)	2014		2013	
	Carrying Value	Weighted Average Effective Rate[1]	Carrying Value	Weighted Average Effective Rate[1]
Province of BC bonds	$ 85	3.9%	$ 72	3.2%
Other provincial government and crown corporation bonds	44	4.0%	40	3.3%
Total	$ 129		$ 112	

[1] *Rate calculated on market yield to maturity.*

Effective December, 2005, all sinking fund payment requirements on all new and outstanding debt were removed.

NOTE 15: ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

(in millions)	2014	2013
Accounts payable	$ 386	$ 328
Accrued liabilities	819	838
Legal settlement	302	-
Current portion of other long-term liabilities (Note 20)	120	98
Dividend payable	167	215
Other	92	65
Total	$ 1,886	$ 1,544

LEGAL SETTLEMENT

On October 4, 2013, the Federal Energy Regulatory Commission (FERC) issued an Order approving the settlement between Powerex and Pacific Gas and Electric, Southern California Edison, San Diego Gas and Electric, the California Attorney General, and the California Public Utilities Commission (the California Parties) arising from events and transactions in the California power market during the 2000 and 2001 period.

The settlement will become final upon the Settlement Effective Date specified in the settlement agreement, which is anticipated to occur in fiscal 2015.

As part of the settlement, Powerex made a net cash payment into escrow of US$273 million which translated to CDN$287 million on the transaction date and CDN$302 million as at March 31, 2014, which is recorded as restricted cash in the statement of financial position. The cash payment will remain in escrow until after occurrence of the Settlement Effective Date. The net cash payment was calculated as the difference between the agreed upon settlement amount of US$750 million and the receivables and interest owing from the California parties to Powerex of US$477 million. The net cash payment was accounted for during the first quarter of fiscal 2014 and an expense of CDN$214 million was recorded. The expense was calculated on the transaction date as the net cash settlement amount of CDN$287 million (US$273 million) less amounts previously accrued related to legal claims of CDN$73 million.

NOTE 16: LONG-TERM DEBT AND DEBT MANAGEMENT

The Company's long-term debt comprises bonds and revolving borrowings obtained under an agreement with the Province.

The Company has a commercial paper borrowing program with the Province which is limited to $4.5 billion, and is included in revolving borrowings. At March 31, 2014, the outstanding amount under the borrowing program was $3,762 million (2013 - $2,573 million).

During fiscal 2014, the Company issued bonds with a par value of $1,150 million (2013 – $1,393 million) a weighted average effective interest rate of 3.9 per cent (2013 – 3.3 per cent) and a weighted average term to maturity of 29.9 years (2013 – 25.4 years).

Long-term debt, expressed in Canadian dollars, is summarized in the following table by year of maturity:

($ amounts in millions of Canadian dollars)	2014				2013			
	Canadian	US	Total	Weighted Average Interest Rate[1]	Canadian	US	Total	Weighted Average Interest Rate[1]
Maturing in fiscal:								
2014	$ -	$ -	$ -	-	$ 500	$ 203	$ 703	6.6
2015	325	-	325	5.5	325	-	325	5.5
2016	150	-	150	5.2	150	-	150	5.2
2017	-	-	-	-	-	-	-	-
2018	40	-	40	4.8	40	-	40	4.8
2019	1,030	221	1,251	4.6	-	-	-	-
1-5 years	1,545	221	1,766	4.8	1,015	203	1,218	6.0
6-10 years	2,500	-	2,500	7.2	3,331	203	3,534	6.3
11-15 years	10	553	563	6.6	110	508	618	6.9
16-20 years	1,610	-	1,610	5.0	1,610	-	1,610	5.0
21-25 years	-	332	332	7.4	-	305	305	7.4
26-30 years	3,273	-	3,273	4.3	3,273	-	3,273	4.3
Over 30 years	1,730	-	1,730	4.0	680	-	680	4.2
Bonds	10,668	1,106	11,774	5.2	10,019	1,219	11,238	5.4
Revolving borrowings	3,504	258	3,762	1.0	1,926	647	2,573	0.9
	14,172	1,364	15,536		11,945	1,866	13,811	
Adjustments to carrying value resulting from hedge accounting	31	22	53		45	22	67	
Unamortized premium, discount, and issue costs	120	(12)	108		267	(11)	256	
	$14,323	$ 1,374	$15,697		$ 12,257	$ 1,877	$ 14,134	
Less: Current portion	(3,829)	(258)	(4,087)		(2,437)	(851)	(3,288)	
Long-term debt	$10,494	$ 1,116	$11,610		$ 9,820	$ 1,026	$ 10,846	

[1] *The weighted average interest rate represents the effective rate of interest on fixed-rate bonds and the current interest rate in effect at March 31 for floating-rate bonds, all before considering the effect of derivative financial instruments used to manage interest rate risk.*

There were no interest rate contracts in place at March 31, 2014 (2013 – asset of $4 million).

Details of interest rate contracts in place at March 31, 2013 are as follows:

($ amounts in millions)	**2014**	2013
Receive fixed, pay floating rate swaps		
Notional amount[1]	$ -	$ 553
Weighted average receive rate	-	4.15%
Weighted average pay rate	-	0.93%
Weighted terms	-	< 1 year
Receive floating, pay fixed rate swaps		
Notional amount[1]	$ -	$ 290
Weighted average receive rate	-	1.45%
Weighted average pay rate	-	4.90%
Weighted terms	-	< 1 year

[1] *Notional amount for a derivative instrument is defined as the contractual amount on which payments are calculated.*

The following foreign currency contracts were in place at March 31, 2014 in a liability position of $31 million (2013 – liability of $157 million). Such contracts are primarily used to hedge U.S. dollar principal and interest payments.

($ amounts in millions)	**2014**	2013
Cross-Currency Swaps		
United States dollar to Canadian dollar - notional amount[1]	-	US$ 200
United States dollar to Canadian dollar - weighted average contract rate	-	1.45
Weighted remaining term	-	< 1 year
Foreign Currency Forwards		
United States dollar to Canadian dollar - notional amount[1]	**US$ 1,091**	US$ 1,462
United States dollar to Canadian dollar - weighted average contract rate	**1.17**	1.12
Weighted remaining term	**10 years**	8 years

[1] *Notional amount for a derivative instrument is defined as the contractual amount on which payments are calculated.*

For more information about the Company's exposure to interest rate, foreign currency and liquidity risk, see Note 19.

NOTE 17: CAPITAL MANAGEMENT

Orders in Council from the Province establish the basis for determining the Company's equity for regulatory purposes, as well as the annual Payment to the Province (see below). Capital requirements are consequently managed through the retention of equity subsequent to the Payment to the Province and a limit on the Payment to the Province if it would cause the debt to equity ratio to exceed 80:20.

The Company monitors its capital structure on the basis of its debt to equity ratio. For this purpose, the applicable Order in Council defines debt as revolving borrowings and interest-bearing borrowings less investments held in sinking funds and cash and cash equivalents. Equity comprises retained earnings, accumulated other comprehensive income (loss) and contributed surplus.

During the period, there were no changes in the approach to capital management.

The debt to equity ratio at March 31, 2014, and March 31, 2013 was as follows:

(in millions)	2014	2013
Total debt, net of sinking funds	$ 15,568	$ 14,022
Less: Cash and cash equivalents	(107)	(60)
Net Debt	$ 15,461	$ 13,962
Retained earnings	$ 3,751	$ 3,369
Contributed surplus	60	60
Accumulated other comprehensive income	54	71
Total Equity	$ 3,865	$ 3,500
Net Debt to Equity Ratio	80 : 20	80 : 20

PAYMENT TO THE PROVINCE

The Company is required to make an annual Payment to the Province (the Payment) on or before June 30 of each year. The Payment is equal to 85 per cent of the Company's net income for the most recently completed fiscal year unless the debt to equity ratio, as defined by the Province, after deducting the Payment, is greater than 80:20. If the Payment would result in a debt to equity ratio exceeding 80:20, then the Payment is the greatest amount that can be paid without causing the debt to equity ratio to exceed 80:20. The Payment accrued at March 31, 2014 is $167 million (March 31, 2013 - $215 million), which is included in accounts payable and accrued liabilities and is less than 85 per cent of the net income due to the 80:20 cap.

NOTE 18: EMPLOYEE BENEFITS – POST-EMPLOYMENT BENEFIT PLANS

The Company provides a defined benefit statutory pension plan to substantially all employees, as well as supplemental arrangements which provide pension benefits in excess of statutory limits. Pension benefits are based on years of membership service and highest five-year average pensionable earnings. Annual cost-of-living increases are provided to pensioners to the extent that funds are available in the indexing fund. Employees make basic and indexing contributions to the plan funds based on a percentage of current pensionable earnings. The Company contributes amounts as prescribed by the independent actuary. The Company is responsible for ensuring that the statutory pension plan has sufficient assets to pay the pension benefits upon retirement of employees. The supplemental arrangements are unfunded. The most recent actuarial funding valuation for the statutory pension plan was performed at December 31, 2012. The next scheduled funding valuation is as at December 31, 2015.

The Company also provides post-employment benefits other than pensions including limited medical, extended health, dental and life insurance coverage for retirees who have at least 10 years of service and qualify to receive pension benefits. Certain benefits, including the short-term continuation of health care and life insurance, are provided to terminated employees or to survivors on the death of an employee. These post-employment benefits other than pensions are not funded. Post-employment benefits include the pay out of benefits that vest or accumulate, such as banked vacation.

Information about the pension benefit plans and post-employment benefits other than pensions is as follows:

(a) The expense for the Company's benefit plans for the years ended at March 31, 2014 and 2013 is recognized in the following line items in the statement of comprehensive income prior to any capitalization of employment costs attributable to property, plant and equipment and intangible asset additions and prior to the application of regulatory accounting:

	Pension Benefit Plans		Other Benefit Plans	
(in millions)	2014	2013	2014	2013
Current service costs charged to personnel operating costs	$ 80	$ 71	$ 14	$ 10
Net interest costs charged to finance costs	44	58	15	15
Total post-employment benefit plan expense	$ 124	$ 129	$ 29	$ 25

Actual return on defined benefit plan assets for the year ended March 31, 2014 was $388 million (2013 - $246 million).

Actuarial gains and losses recognized in other comprehensive income are nil (2013 – nil). As per Note 13, in accordance with Prescribed Standards and as approved by the BCUC, actuarial gains and losses, as summarized in Note 18(c) below, are deferred to the Non-Current Pension Cost regulatory account.

(b) Information about the Company's defined benefit plans at March 31, in aggregate, is as follows:

	Pension Benefit Plans		Other Benefit Plans	
(in millions)	2014	2013	2014	2013
Defined benefit obligation of funded plans	$ (3,648)	$ (3,575)	$ -	$ -
Defined benefit obligation of unfunded plans	(136)	(127)	(374)	(361)
Fair value of plan assets	2,985	2,667	-	-
Plan deficit	$ (799)	$ (1,035)	$ (374)	$ (361)

The Company determined that there was no minimum funding requirement adjustment required in fiscal 2014 and fiscal 2013 in accordance with IFRIC 14, *The Limit on Defined Benefit Asset, Minimum Funding Requirements and Their Interaction.*

(c) Movement of defined benefit obligations and defined benefit plan assets during the year:

	Pension Benefit Plans		Other Benefit Plans	
(in millions)	**2014**	2013	**2014**	2013
Defined benefit obligation				
Opening defined benefit obligation	**$ 3,702**	$ 3,365	**$ 361**	$ 320
Current service cost	**80**	71	**14**	10
Interest cost	**218**	188	**15**	15
Benefits paid[1]	**(169)**	(162)	**(12)**	(11)
Employee contributions	**28**	26	**-**	-
Actuarial (gains) losses[2]	**(75)**	214	**(4)**	27
Defined benefit obligation, end of year	**3,784**	3,702	**374**	361
Fair value of plan assets				
Opening fair value	**2,667**	2,503	**n/a**	n/a
Expected return on plan assets	**174**	130	**n/a**	n/a
Employer contributions	**65**	49	**n/a**	n/a
Employee contributions	**28**	26	**n/a**	n/a
Benefits paid[1]	**(163)**	(157)	**n/a**	n/a
Actuarial gains[2]	**214**	116	**n/a**	n/a
Fair value of plan assets, end of year	**2,985**	2,667	**-**	-
Accrued benefit liability	**$ (799)**	$ (1,035)	**$ (374)**	$ (361)

[1] *Benefits paid under Pension Benefit Plans include $16 million (2013 - $14 million) of settlement payments.*
[2] *Actuarial gains/losses are included in the Non-Current Pension Cost regulatory account and are comprised of experience gains on return of plan assets of $214 million, and changes in discount rate and experience gains on the pension obligation of $164 million, partially offset by changes in mortality assumptions of $89 million.*

(d) The significant assumptions adopted in measuring the Company's accrued benefit obligations as at each March 31 year end are as follows:

	Pension Benefit Plans		Other Benefit Plans	
	2014	2013	**2014**	2013
Discount rate				
Benefit cost	**4.00%**	4.62%	**4.20%**	4.55%
Accrued benefit obligation	**4.37%**	4.00%	**4.59%**	4.20%
Expected long term rate of return on plan assets	**4.00%**	4.62%	**n/a**	n/a
Rate of compensation increase				
Benefit cost	**3.35%**	3.70%	**n/a**	n/a
Accrued benefit obligation	**3.35%**	3.35%	**n/a**	n/a
Health care cost trend rates				
Weighted average health care cost trend rate	**n/a**	n/a	**5.79%**	5.72%
Weighted average ultimate health care cost trend rate	**n/a**	n/a	**4.42%**	4.38%
Year ultimate health care cost trend rate will be achieved	**n/a**	n/a	**2027**	2026

The valuation cost method for the accrued benefit obligation is the projected accrued benefit pro-rated on service.

NOTE 19: FINANCIAL INSTRUMENTS

FINANCIAL RISKS

The Company is exposed to a number of financial risks in the normal course of its business operations, including market risks resulting from fluctuations in commodity prices, interest rates and foreign currency exchange rates, as well as credit risks and liquidity risks. The nature of the financial risks and the Company's strategy for managing these risks has not changed significantly from the prior period.

The following discussion is limited to the nature and extent of risks arising from financial instruments, as defined under IFRS 7, *Financial Instruments: Disclosures*. However, for a complete understanding of the nature and extent of financial risks the Company is exposed to, this note should be read in conjunction with the Company's discussion of Risk Management found in the Management's Discussion and Analysis section of the 2014 Annual Report.

(a) Credit Risk

Credit risk refers to the risk that one party to a financial instrument will cause a financial loss for a counterparty by failing to discharge an obligation. The Company is exposed to credit risk related to cash and cash equivalents, restricted cash, sinking fund investments, and derivative instruments. It is also exposed to credit risk related to accounts receivable arising from its day-to-day electricity and natural gas sales in and outside British Columbia. Maximum credit risk with respect to financial assets is limited to the carrying amount presented on the statement of financial position with the exception of U.S. dollar sinking funds classified as held-to-maturity and carried on the statement of financial position at amortized cost of $129 million. The maximum credit risk exposure for these U.S. dollar sinking funds as at March 31, 2014 is its fair value of $143 million. The Company manages this risk through Board-approved credit risk management policies which contain limits and procedures related to the selection of counterparties. Exposures to credit risks are monitored on a regular basis. In addition, the Company has credit loss insurance that covers most credit exposures with U.S. counterparties or transactions delivered in the U.S.

(b) Liquidity Risk

Liquidity risk refers to the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities. The Company manages liquidity risk by forecasting cash flows to identify financing requirements and by maintaining committed credit facilities. The Company's long-term debt comprises bonds and revolving borrowings obtained under an agreement with the Province. Cash from operations reduces the Company's liquidity risk. The Company does not believe that it will encounter difficulty in meeting its obligations associated with financial liabilities.

(c) Market Risks

Market risk refers to the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises three types of risk: currency risk, interest rate risk, and price risk, such as changes in commodity prices and equity values. The Company monitors its exposure to market fluctuations and may use derivative contracts to manage these risks, as it considers appropriate. Other than in its energy trading subsidiary Powerex, the Company does not use derivative contracts for trading or speculative purposes.

(i) Currency Risk

Currency risk refers to the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in foreign exchange rates. The Company's currency risk is primarily with the U.S. dollar.

The majority of the Company's currency risk arises from long-term debt in the form of U.S. dollar denominated bonds. Energy commodity prices are also subject to currency risk as they are primarily denominated in U.S. dollars.

As a result, the Company's trade revenues and purchases of energy commodities, such as electricity and natural gas, and associated accounts receivable and accounts payable, are affected by the Canadian/U.S. dollar exchange rate. In addition, all commodity derivatives and contracts priced in U.S. dollars are also affected by the Canadian/U.S. dollar exchange rate.

The Company actively manages its currency risk through a number of Board-approved policy documents. The Company uses cross-currency swaps and forward foreign exchange purchase contracts to achieve and maintain the Board-approved U.S. dollar exposure targets.

(ii) Interest Rate Risk

Interest rate risk refers to the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market interest rates. The Company is exposed to changes in interest rates primarily through its variable rate debt and the active management of its debt portfolio including its related sinking fund assets and temporary investments. The Company's Board-approved debt management strategies include maintaining a percentage of variable interest rate debt within a certain range. The Company enters into interest rate swaps to achieve and maintain the target range of variable interest rate debt.

(iii) Commodity Price Risk

The Company is exposed to commodity price risk as fluctuations in electricity prices and natural gas prices could have a materially adverse effect on its financial condition. Prices for electricity and natural gas fluctuate in response to changes in supply and demand, market uncertainty, and a variety of other factors beyond the Company's control.

The Company enters into derivative contracts to manage commodity price risk. Risk management strategies, policies and limits are designed to ensure the Company's risks and related exposures are aligned with the Company's business objectives and risk tolerance. Risks are managed within defined limits that are regularly reviewed by the Board of Directors.

CATEGORIES OF FINANCIAL INSTRUMENTS

Finance charges, including interest income and expenses, for financial instruments disclosed in the following table are prior to the application of regulatory accounting for the years ended March 31, 2014 and 2013.

The following table provides a comparison of carrying values and fair values for non-derivative financial instruments as at March 31, 2014 and 2013. The non-derivative financial instruments, where carrying value differs from fair value, would be classified as Level 2 of the fair value hierarchy.

(in millions)	2014 Carrying Value	2014 Fair Value	2013 Carrying Value	2013 Fair Value	Interest Income (Expense) recognized in Finance Charges 2014	Interest Income (Expense) recognized in Finance Charges 2013
Financial Assets and Liabilities at Fair Value Through Profit or Loss:						
Short-term investments	$ 33	$ 33	$ 22	$ 22	$ 2	$ 1
Designated long-term debt	-	-	(565)	(565)	(13)	(46)
Loans and Receivables:						
Accounts receivable and accrued revenue	718	718	651	651	-	-
Restricted cash	355	355	70	70	-	-
Cash	74	74	38	38	-	-
Held to Maturity:						
Sinking funds – US	129	143	112	135	6	6
Other Financial Liabilities:						
Accounts payable and accrued liabilities	(1,886)	(1,886)	(1,544)	(1,544)	-	-
Revolving borrowings - CAD	(3,504)	(3,504)	(1,926)	(1,926)	(24)	(19)
Revolving borrowings - US	(258)	(258)	(647)	(647)	(1)	(1)
Long-term debt (including current portion due in one year)	(11,935)	(13,405)	(10,996)	(13,073)	(601)	(555)
First Nations liability (long-term portion)	(385)	(725)	(374)	(1,125)	(21)	(17)
Finance Lease Obligation (long-term portion)	(259)	(259)	(275)	(275)	(24)	(26)

For non-derivative financial assets and liabilities classified as financial assets and liabilities at fair value through profit or loss, a $12 million gain (2013 - $37 million gain) has been recognized in net income for the year relating to changes in fair value. For short-term investments, loans and receivables, and accounts payable and accrued liabilities, the carrying value approximates fair value due to the short duration of these financial instruments.

The fair value of derivative instruments designated and not designated as hedges, was as follows:

(in millions)	**2014 Fair Value**	2013 Fair value
Derivative Instruments Used to Hedge Risk Associated with Long-term Debt:		
Foreign currency contracts (cash flow hedges for $US denominated long-term debt)	$ (36)	$ (160)
Interest rate swaps (fair value hedges for debt)	-	4
	(36)	(156)
Non-Designated Derivative Instruments:		
Foreign currency contracts	5	3
Commodity derivatives	23	(3)
	28	-
Net liability	$ (8)	$ (156)

The carrying value of derivative instruments designated and not designated as hedges was the same as the fair value.

The derivatives are represented on the statement of financial position as follows:

(in millions)	**2014**	2013
Current portion of derivative financial instrument assets	$ 96	$ 83
Current portion of derivative financial instrument liabilities	(76)	(172)
Derivative financial instrument assets, long-term	27	27
Derivative financial instrument liabilities, long-term	(55)	(94)
Net liability	$ (8)	$ (156)

For designated cash flow hedges for the year ended March 31, 2014, a gain of $37 million (2013 - $5 million loss) was recognized in other comprehensive income. For the year ended March 31, 2014, $70 million (2013 - $9 million) was removed from other comprehensive income and reported in net income, offsetting foreign exchange losses (2013 – losses) recorded in the year.

For the year ended March 31, 2014, a gain of $63 million (2013 - $9 million loss) was recognized in finance charges with respect to foreign currency contracts for U.S. short-term borrowings. These economic hedges offset $69 million of foreign exchange revaluation losses (2013 - $5 million gain) recorded with respect to U.S. short-term borrowings for the year ended March 31, 2014. A net gain of $9 million (2013 - $3 million loss) was recorded in trade revenue for the year ended March 31, 2014 with respect to commodity derivatives.

COMMODITY DERIVATIVES

Additional information related to the fair value of the commodity derivatives is as follows:

As at March 31, 2014 *($ in millions)*	Notional Quantity of Natural Gas (in TJ)	Notional Quantity of Electricity (in GWh)	Carrying Value	Fair Value	Maximum Term (in months)
Current assets	27,192	8	$ 90	$ 90	12
Long term assets	1,063	686	9	9	54
Current liabilities	28,962	710	(75)	(75)	12
Long-term liabilities	1,232	180	(1)	(1)	67
Total			$ 23	$ 23	

As at March 31, 2013 *($ in millions)*	Notional Quantity of Natural Gas (in TJ)	Notional Quantity of Electricity (in GWh)	Carrying Value	Fair Value	Maximum Term (in months)
Current assets	22,371	6,896	$ 71	$ 71	12
Long term assets	451	374	21	21	66
Current liabilities	46,598	6,296	(80)	(80)	12
Long-term liabilities	2,100	186	(15)	(15)	79
Total			$ (3)	$ (3)	

Notional quantities in the above tables are presented on a net basis and do not necessarily represent the amounts to be exchanged by the parties to the instruments. Furthermore, the magnitude of the notional amounts does not necessarily correlate to the carrying value or fair value of the commodity derivatives.

INCEPTION GAINS AND LOSSES

Changes in deferred inception gains and losses arising from the determination of fair value of derivative financial instruments which are not supported by observable current market transactions or valuation models using only observable market data are as follows:

(in millions)	2014	2013
Unamortized gain at beginning of year	$ (58)	$ (70)
New transactions	1	(2)
Amortization	7	14
Unamortized gain at end of year	$ (50)	$ (58)

CREDIT RISK

DOMESTIC ELECTRICITY RECEIVABLES

A customer application and a credit check are required prior to initiation of services. For customers with no BC Hydro credit history, call center agents ensure accounts are secured either by a credit bureau check, a cash security deposit, or a credit reference letter.

The value of domestic and trade accounts receivable, by age and the related provision for doubtful accounts are presented in the following table.

DOMESTIC AND TRADE ACCOUNTS RECEIVABLE NET OF ALLOWANCE FOR DOUBTFUL ACCOUNTS

(in millions)	2014	2013
Current	$ 472	$ 419
Past due (30-59 days)	32	30
Past due (60-89 days)	9	10
Past due (More than 90 days)	7	5
	520	464
Allowance for doubtful accounts	(8)	(6)
Total	$ 512	$ 458

At the end of each reporting year, a review of the provision for doubtful accounts is performed. It is an assessment of the potential amount of domestic and trade accounts receivable which will not be paid by customers after the statement of financial position date. The assessment is made by reference to age, status and risk of each receivable, current economic conditions, and historical information.

FINANCIAL ASSETS ARISING FROM THE COMPANY'S TRADING ACTIVITIES

A substantial majority of the Company's counterparties associated with its trading activities are in the energy sector. This industry concentration has the potential to impact the Company's overall exposure to credit risk in that the counterparties may be similarly affected by changes in economic, regulatory, political, and other factors. The Company manages credit risk by authorizing trading transactions within the guidelines of the Company's risk management policies, by monitoring the credit risk exposure and credit standing of counterparties on a regular basis, and by obtaining credit assurances from counterparties to which they are entitled under contract.

The Company enters into derivative transactions under International Swap Dealers Association (ISDA) and Western Systems Power Pool (WSPP) or similar master netting agreements and presents these transactions on a gross basis under derivative commodity assets/liabilities in the statement of financial position. These master netting agreements do not meet the criteria for offsetting as the Company does not have the legal enforceable right to offset recognized amounts.

Under the Company's trading agreements, the amounts owed by each counterparty that are due on a single day in respect of all transactions outstanding in the same currency under the same agreement are aggregated into a single net amount being payable by one party to the other. Such receivable or payable amounts meet the criteria for offsetting and are presented as such on the Company's statement of financial position.

The following table sets out the carrying amounts of recognized financial instruments that are subject to the above agreements:

As at March 31, 2014 *(in millions)*	Gross Derivative Instruments Presented in Statement of Financial Position	Related Instruments That are Not Offset	Net Amount
Derivative commodity assets	$ 99	$ 2	$ 97
Derivative commodity liabilities	76	2	74

As at March 31, 2013 *(in millions)*	Gross Derivative Instruments Presented in Statement of Financial Position	Related Instruments That are Not Offset	Net Amount
Derivative commodity assets	$ 92	$ 5	$ 87
Derivative commodity liabilities	95	5	90

With respect to these financial assets, the Company assigns credit limits for counterparties based on evaluations of their financial condition, net worth, regulatory environment, cost recovery mechanisms, credit ratings, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically and a detailed credit analysis is performed at least annually. Further, the Company has tied a portion of its contracts to master agreements that require security in the form of cash or letters of credit if current net receivables and replacement cost exposure exceed contractually specified limits.

The following table outlines the distribution, by credit rating, of financial assets that are neither past due nor impaired:

As at March 31, 2014	Investment Grade %	Unrated %	Non-Investment Grade %	Total %
Accounts receivable	88	1	11	100
Assets from trading activities	100	0	0	100

As at March 31, 2013	Investment Grade %	Unrated %	Non-Investment Grade %	Total %
Accounts receivable	91	3	6	100
Assets from trading activities	100	0	0	100

The outstanding amount of collateral received from customers at March 31, 2014 was $7 million (2013 - $2 million).

LIQUIDITY RISK

The following table details the remaining contractual maturities at March 31, 2014 of the Company's non-derivative financial liabilities and derivative financial liabilities, which are based on contractual undiscounted cash flows. Interest payments have been computed using contractual rates or, if floating, based on rates current at March 31, 2014. In respect of the cash flows in U.S. dollars, the exchange rate as at March 31, 2014 has been used.

(in millions)	Carrying Value	Fiscal 2015	Fiscal 2016	Fiscal 2017	Fiscal 2018	Fiscal 2019	Fiscal 2020 and thereafter
Non-Derivative Financial Liabilities							
Total accounts payable and other payables (excluding interest accruals and current portion of lease obligations and other long-term financial liabilities)	$ 1,680	$(1,680)	$ -	$ -	$ -	$ -	$ -
Long-term debt (including interest payments)	15,854	(942)	(758)	(600)	(639)	(1,839)	(17,574)
Lease obligations	276	(77)	(80)	(81)	(83)	(37)	(762)
Other long-term financial liabilities	417	(13)	(13)	(16)	(12)	(13)	(836)
		(2,712)	(851)	(697)	(734)	(1,889)	(19,172)
Derivative Financial Liabilities							
Forward foreign exchange contracts used for hedging	54						
Cash outflow		-	-	-	-	-	(719)
Cash inflow		-	-	-	-	-	633
Other forward foreign exchange contracts designated at fair value	1						
Cash outflow		(106)	-	-	-	-	-
Cash inflow		105	-	-	-	-	-
Financially settled commodity derivative liabilities designated at fair value	65	(65)	-	-	-	-	-
Physically settled commodity derivative liabilities designated at fair value	11	(37)	-	-	-	-	-
		(103)	-	-	-	-	(86)
Total Financial Liabilities		(2,815)	(851)	(697)	(734)	(1,889)	(19,258)
Derivative Financial Assets							
Financially settled commodity derivative assets designated at fair value	(87)	43	1	-	-	-	-
Physically settled commodity derivative assets designated at fair value	(12)	49	23	30	6	5	3
Net Financial Liabilities[1]		**$(2,723)**	**$ (827)**	**$ (667)**	**$ (728)**	**$(1,884)**	**$ (19,255)**

[1] *The Company believes that the liquidity risk associated with commodity derivative financial liabilities needs to be considered in conjunction with the profile of payments or receipts arising from commodity derivative financial assets. It should be noted that cash flows associated with future energy sales and commodity contracts which are not considered financial instruments under IAS 39 are not included in this analysis, which is prepared in accordance with IFRS 7.*

MARKET RISKS

(a) Currency Risk

Sensitivity Analysis

A $0.01 strengthening or weakening of the U.S. dollar against the Canadian dollar at March 31, 2014 would have an impact of $1 million but as a result of regulatory accounting would have no impact on net income and would have an immaterial impact on other comprehensive income. The Finance Charges regulatory account that captures all variances from forecasted finance charges as described in Note 13 eliminates any impact on net income. This analysis assumes that all other variables, in particular interest rates, remain constant.

This sensitivity analysis has been determined assuming that the change in foreign exchange rates had occurred at March 31, 2014 and been applied to each of the Company's exposures to currency risk for both derivative and non-derivative financial instruments in existence at that date, and that all other variables remain constant. The stated change represents management's assessment of reasonably possible changes in foreign exchange rates over the period until the next statement of financial position date.

(b) Interest Rate Risk

Fair value sensitivity analysis for fixed rate non-derivative instruments

The Company accounts for certain fixed rate financial assets and liabilities as financial assets and liabilities at fair value through profit or loss. A change in interest rates at March 31, 2014 would not affect net income and would have no impact on other comprehensive income with respect to these fixed rate instruments. The Finance Charges regulatory account that captures all variances from forecasted finance charges as described in Note 13 eliminates any impact on net income. This analysis assumes that all other variables, in particular foreign exchange rates, remain constant.

Sensitivity analysis for variable rate non-derivative instruments and derivative instruments

An increase or decrease of 100-basis points in interest rates at March 31, 2014 would have an impact on net income of $41 million but as a result of regulatory accounting would have no impact on net income and would have no material impact on other comprehensive income. The Finance Charges regulatory account that captures all variances from forecasted finance charges as described in Note 13 eliminates any impact on net income. This analysis assumes that all other variables, in particular foreign exchange rates, remain constant.

This sensitivity analysis has been determined assuming that the change in interest rates had occurred at March 31, 2014 and been applied to each of the Company's exposure to interest rate risk for both derivative and non-derivative financial instruments in existence at that date, and that all other variables remain constant. The stated change represents management's assessment of reasonably possible changes in interest rates over the period until the next statement of financial position date.

(c) Commodity Price Risk

Sensitivity Analysis

Commodity price risk refers to the risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in commodity prices.

BC Hydro's subsidiary Powerex trades and delivers energy and associated products and services throughout North America. As a result, the Company has exposure to movements in commodity prices for commodities Powerex trades, including electricity, natural gas and associated derivative products. Prices for these commodities fluctuate in response to changes in supply and demand, market uncertainty, and other factors beyond the Company's control.

The Company manages these exposures through its Board-approved risk management policies, which limit components of and overall market risk exposures, pre-define approved products and mandate regular reporting of exposures.

The Company's risk management policy for trading activities defines various limits and controls, including Value at Risk ("VaR") limits, mark-to-market limits, and various transaction specific limits which are monitored on a daily basis. VaR estimates the pre-tax forward trading loss that could result from changes in commodity prices, with a specific level of confidence, over a specific time period. Powerex uses an industry standard Monte Carlo VaR model to determine the potential change in value of its forward trading portfolio over a 10-day holding period, within a 95 per cent confidence level, resulting from normal market fluctuations.

VaR as an estimate of price risk has several limitations. The VaR model uses historical information to determine potential future volatility, assuming that price movements in the recent past are indicative of near-future price movements. It cannot forecast unusual events which can lead to extreme price movements. In addition, it is sometimes difficult to appropriately estimate the VaR associated with illiquid or non-standard products. As a result, Powerex uses additional measures to supplement the use of VaR to estimate price risk. These include the use of a Historic VaR methodology, stress tests and notional limits for illiquid or emerging products.

Powerex's VaR, calculated under this methodology, was approximately $9 million at March 31, 2014 (2013 - $11 million).

FAIR VALUE HIERARCHY

The following provides an analysis of financial instruments that are measured subsequent to initial recognition at fair value, grouped based on the lowest level of input that is significant to that fair value measurement.

The inputs used in determining fair value are characterized by using a hierarchy that prioritizes inputs based on the degree to which they are observable. The three levels of the fair value hierarchy are as follows:

- Level 1 - values are quoted prices (unadjusted) in active markets for identical assets and liabilities.
- Level 2 - inputs are those other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, as of the reporting date.
- Level 3 - inputs are those that are not based on observable market data.

The following tables present the financial instruments measured at fair value for each hierarchy level as at March 31, 2014 and 2013:

As at March 31, 2014 *(in millions)*	Level 1	Level 2	Level 3	Total
Short-term investments	$ 33	$ -	$ -	$ 33
Derivatives designated as hedges	-	18	-	18
Derivatives not designated as hedges	21	35	49	105
Total financial assets carried at fair value	$ 54	$ 53	$ 49	$ 156
Derivatives designated as hedges	$ -	$ (54)	$ -	$ (54)
Derivatives not designated as hedges	(22)	(49)	(6)	(77)
Total financial liabilities carried at fair value	$ (22)	$ (103)	$ (6)	$ (131)

As at March 31, 2013 *(in millions)*	Level 1	Level 2	Level 3	Total
Short-term investments	$ 22	$ -	$ -	$ 22
Derivatives designated as hedges	-	10	-	10
Derivatives not designated as hedges	13	37	45	95
Total financial assets carried at fair value	$ 35	$ 47	$ 45	$ 127
Derivatives designated as hedges	$ -	$ (166)	$ -	$ (166)
Derivatives not designated as hedges	(25)	(59)	(11)	(95)
Total financial liabilities carried at fair value	$ (25)	$ (225)	$ (11)	$ (261)

The Company determines Level 2 fair values for debt securities and derivatives using discounted cash flow techniques, which use contractual cash flows and market-related discount rates.

Level 2 fair values for energy derivatives are determined using inputs other than unadjusted quoted prices that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices). Level 2 includes bilateral and over-the-counter contracts valued using interpolation from observable forward curves or broker quotes from active markets for similar instruments and other publicly available data, and options valued using industry-standard and accepted models incorporating only observable data inputs.

There were no transfers between Levels 1 and 2 during the period.

Powerex holds congestion products and structured power transactions that require the use of unobservable inputs when observable inputs are unavailable. Congestion products are valued using forward spreads at liquid hubs that include adjustments for the value of energy at different locations relative to the liquid hub as well as other adjustments that may impact the valuation. Option pricing models are used when the congestion product is an option. Structured power transactions are valued using standard contracts at a liquid hub with adjustments to account for the quality of the energy, the receipt or delivery location, and delivery flexibility where appropriate. Significant unobservable inputs include adjustments for the quality of the energy and the transaction location relative to the reference standard liquid hub.

The following table reconciles the changes in the balance of financial instruments carried at fair value on the statement of financial position, classified as Level 3, for the years ended March 31, 2014 and 2013:

(in millions)	
Balance at March 31, 2012	$ 47
Cumulative impact of net gain recognized	24
New transactions	10
Existing transactions settled	(47)
Balance at March 31, 2013	34
Cumulative impact of net gain recognized	9
New transactions	3
Existing transactions settled	(3)
Balance at March 31, 2014	$ 43

Level 3 fair values for energy derivatives are determined using inputs that are not observable. Level 3 includes instruments valued using observable prices adjusted for unobservable basis differentials such as delivery location and product quality, instruments which are valued by extrapolation of observable market information into periods for which observable market information is not yet available, and instruments valued using internally developed or non-standard valuation models.

A net gain of $15 million (2013 - $2 million loss) recognized in net income during the year ended March 31, 2014 relates to Level 3 financial instruments held at March 31, 2014. The net gain is recognized in trade revenue.

The Company believes that the use of reasonable alternative valuation input assumptions in the calculation of Level 3 fair values would not result in significantly different fair values. Methodologies and procedures regarding Powerex's energy trading Level 3 fair value measurements are determined by the Powerex's Risk Management group. Level 3 Powerex fair values are calculated within the Powerex's Risk Management Policy for trading activities based on underlying contractual data as well as observable and non-observable inputs. Development of non-observable inputs requires the use of judgment. To ensure reasonability, Level 3 fair value measurements are reviewed and validated by Powerex's Risk Management and Finance departments on a quarterly basis.

NOTE 20: OTHER LONG-TERM LIABILITIES

(in millions)	2014	2013
Provisions		
Environmental liabilities	$ 333	$ 340
Decommissioning obligations	50	52
Other	22	43
Total Provisions	405	435
First Nations liabilities	417	387
Finance lease obligations	276	292
Other liabilities	28	-
Deferred revenue - Skagit River Agreement	433	423
	1,559	1,537
Less: Current portion, included in accounts payable and accrued liabilities	(120)	(98)
Total	$ 1,439	$ 1,439

Changes in each class of provision during the financial year are set out below:

	Environmental	Decommissioning	Other	Total
Balance at March 31, 2013	$ 340	$ 52	$ 43	$ 435
Made during the period	14	-	14	28
Used during the period	(38)	(3)	(2)	(43)
Transfer to accounts payable and accrued liabilities (Note 15)	-	-	(33)	(33)
Changes in estimate	12	-	-	12
Accretion	5	1	-	6
Balance at March 31, 2014	$ 333	$ 50	$ 22	$ 405

ENVIRONMENTAL LIABILITIES

The Company has recorded a liability for the estimated future environmental expenditures related to present or past activities of the Company. The Company's recorded liability is based on management's best estimate of the present value of the future expenditures expected to be required to comply with existing regulations. There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations and advances in remediation technologies. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively.

The undiscounted cash flow related to the Company's environmental liabilities, which will be incurred between fiscal 2015 and 2045, is approximately $436 million and was determined based on current cost estimates. A range of discount rates between 1.0 to 3.0 per cent were used to calculate the net present value of the obligations.

As described in Note 13, the Company has recorded a regulatory asset in relation to the environmental liabilities.

DECOMMISSIONING OBLIGATIONS

The Company's decommissioning obligation provision consists of estimated removal and destruction costs associated with certain PCB contaminated assets and certain submarine cables. The Company has determined its best estimate of the undiscounted amount of cash flows required to settle remediation obligations at $87 million (2013 – $89 million), which will be settled between fiscal 2015 and 2054. The undiscounted cash flows are then discounted by a range of discount rates between 1.0 to 3.0 per cent were used to calculate the net present value of the obligations. The obligations are re-measured at each period end to reflect changes in estimated cash flows and discount rates.

FIRST NATIONS LIABILITIES

The First Nations liabilities consist primarily of settlement costs related to agreements reached with various First Nations groups. First Nations liabilities are recorded as financial liabilities and are measured at fair value on initial recognition with future contractual cash flows being discounted at rates ranging from 4.4 per cent to 5.0 per cent. These liabilities are measured at amortized cost and not re-measured for changes in discount rates. The First Nations liabilities are non-interest bearing.

FINANCE LEASE LIABILITIES

The finance lease obligations are related to long-term energy purchase agreements. The present value of the lease obligations were discounted at rates ranging from 7.9 per cent to 9.3 per cent with contract terms of 25 years expiring from 2018 until 2036. Finance lease liabilities are payable as follows:

	Future minimum lease payments	Interest	Present value of minimum lease payments	Future minimum lease payments	Interest	Present value of minimum lease payments
(in millions)	2014	2014	2014	2013	2013	2013
Less than one year	$ 40	$ 23	$ 17	$ 40	$ 24	$ 16
Between one and five years	162	89	73	181	96	85
More than five years	333	147	186	353	162	191
Total minimum lease payments	$ 535	$ 259	$ 276	$ 574	$ 282	$ 292

NOTE 21: COMMITMENTS AND CONTINGENCIES

ENERGY COMMITMENTS

BC Hydro (excluding Powerex) has long-term energy purchase contracts to meet a portion of its expected future domestic electricity requirements. The expected obligations to purchase energy under these contracts have a total value of approximately $53,685 million of which approximately $337 million relates to the purchase of natural gas and natural gas transportation contracts, at market prices over 30 years. The remaining commitments are at predetermined prices. Included in the total value of the long-term energy purchase agreements are $535 million accounted for as obligations under capital leases. The total BC Hydro combined payments are estimated to be approximately $1,331 million for less than one year, $6,008 million between one and five years, and $46,346 million for more than five years.

Powerex has energy purchase commitments with an estimated minimum payment obligation of $2,787 million extending to 2025. The total Powerex energy purchase commitments are estimated to be approximately $841 million for less than one year, $958 million between one and five years, and $988 million for more than five years. Powerex has energy sales commitments of $873 million extending to 2025 with estimated amounts of $569 million for less than one year, $273 million between one and five years, and $31 million for more than five years.

LEASE AND SERVICE AGREEMENTS

The Company has entered into various agreements to lease facilities or assets treated as operating leases, or to purchase business support services. The agreements cover periods of up to 10 years, and the aggregate minimum payments are approximately $423 million. Payments are $121 million for less than 1 year, $269 million between one and five years, and $33 million for more than five years.

LEGAL CONTINGENCIES

a) Facilities and Rights of Way: the Company is subject to existing and pending legal claims relating to alleged infringement and damages in the operation and use of facilities owned by the Company. These claims may be resolved unfavourably with respect to the Company and may have a significant adverse effect on the Company's financial position. For existing claims in respect of which settlement negotiations have advanced to the extent that potential settlement amounts can reasonably be predicted, management has recorded a liability for the potential costs of those settlements. For pending claims, management believes that any loss exposure that may ultimately be incurred may differ materially from management's current estimates. Management has not disclosed the ranges of expected outcomes due to the potentially adverse effect on the negotiation process for these claims.

b) Due to the size, complexity and nature of the Company's operations, various other legal matters are pending. It is not possible at this time to predict with any certainty the outcome of such litigation. Management believes that any settlements related to these matters will not have a material effect on the Company's consolidated financial position or results of operations.

c) The Company and its subsidiaries have outstanding letters of credit totalling $913 million (2013 - $389 million), of which there is US $106 million (2013 – US $115 million).

NOTE 22: RELATED PARTY TRANSACTIONS

SUBSIDIARIES

The principal subsidiaries of BC Hydro are Powerex, Powertech, and Columbia Hydro Constructors Ltd.

All companies are wholly owned and incorporated in Canada and all ownership is in the form of common shares. Powerex is involved in the marketing and trading of power and gas in Canada and the United States. Powertech offers services to solve technical problems with power equipment and systems in Canada and throughout the world. Columbia provides construction services in support of certain BC Hydro capital programs.

All intercompany transactions and balances are eliminated upon consolidation.

RELATED PARTIES

As a Crown corporation, the Company and the Province are considered related parties. All transactions between the Company and its related parties are considered to possess commercial substance and are consequently recorded at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The related party transactions are summarized below:

(in millions)	2014	2013
Balance Sheet		
Accounts receivable	$ 96	$ 109
Accounts payable and accrued liabilities	227	274
Amounts incurred/accrued during the year include:		
Water rental fees	372	348
Cost of energy sales	170	89
Taxes	125	123
Interest	644	628
Payment to the Province	167	215

The Company's debt is either held or guaranteed by the Province (see Note 16). Under an agreement with the Province, the Company indemnifies the Province for any credit losses incurred by the Province related to interest rate and foreign currency contracts entered into by the Province on the Company's behalf. At March 31, 2014, the aggregate exposure under this indemnity totaled approximately $22 million (2013 - $20 million). The Company has not experienced any losses to date under this indemnity.

The Company and British Columbia Investment Management Corporation ("bcIMC") are related parties and are both wholly owned by the Province. The Company has responsibility for administration of the British Columbia Hydro and Power Authority Pension Plan and uses internal and external service providers for this purpose. It has engaged bcIMC to manage investments on behalf of the plan. bcIMC uses internal and external investment managers for this purpose. Refer to Note 18 for the Company contributions to the pension plan for 2014 and 2013.

KEY MANAGEMENT PERSONNEL AND BOARD COMPENSATION

Key management personnel and board compensation includes compensation to the Company's executive officers, executive vice presidents, senior vice presidents and board of directors

(in millions)		2014		2013
Short-term employee benefits	$	4	$	3
Post-employment benefits		1		1

FINANCIAL AND OPERATING STATISTICS

FINANCIAL STATISTICS

for the years ended or as at March 31 (millions of dollars)	2014	2013	2012[6]	2011[6]	2010[2,6]
Revenues	$ 5,392	$ 4,898	$ 4,730	$ 4,016	$ 4,028
Expenses					
Energy costs	2,146	1,806	1,876	1,415	1,621
Other operating expenses[1]	901	894	820	860	795
Amortization	995	953	793	533	487
Taxes	203	196	184	184	178
Finance charges	598	540	499	435	500
	4,843	4,389	4,172	3,427	3,581
Net Income	$ 549	$ 509	$ 558	$ 589	$ 447
Property, Plant and Equipment & Intangible Assets					
At cost[3]	$20,889	$18,932	$17,161	$23,334	$21,300
Less: Accumulated depreciation[3]	1,863	1,268	758	7,788	7,305
Net Book Value	$19,026	$17,664	$16,403	$15,546	$13,995
Property, Plant & Equipment and Intangible Asset Expenditures					
Sustaining	$ 979	$ 1,009	$ 956	$ 865	$ 948
Growth	1,057	920	747	654	1,458
Total Property, Plant & Equipment and Intangible Asset Expenditures[4]	$ 2,036	$ 1,929	$ 1,703	$ 1,519	$ 2,406
Net Long-Term Debt[5]	$15,461	$13,962	$12,833	$11,520	$10,696
Retained Earnings	$ 3,751	$ 3,369	$ 3,075	$ 2,747	$ 2,621
Debt to Equity Ratio	80 : 20	80 : 20	80 : 20	80 : 20	80 : 20

1 *Personnel, materials & external services, capitalized costs and other costs, as per the operating cost note in the consolidated financial statements.*

2 *In F2011, BC Hydro changed its presentation of the impact of regulation on its statement of comprehensive income. Regulatory Transfers were previously on a single line item whereas in F2011 to F2014, they are netted against the corresponding expense or revenue line item. F2010 was restated to conform to the current presentation.*

3 *F2012 to F2014 information was prepared in accordance with the Prescribed Standards. Arising on transition from Canadian Generally Accepted Accounting Principles (GAAP) to the Prescribed Standards and with the application of the deemed cost exemption, the net book value of property, plant and equipment and intangible assets for BC Hydro entities subject to rate regulation at April 1, 2011 have become the opening cost of property, plant and equipment and intangible assets under the Prescribed Standards except for finance leases.*

4 *Total property, plant and equipment and intangible asset expenditures include non-cash items.*

5 *Consists of long-term debt, including the current portion, net of sinking funds and cash and cash equivalents.*

6 *F2012 to F2014 information was prepared in accordance with the Prescribed Standards and F2012 information has been restated to Prescribed Standards for comparative purposes. Financial information for F2010 to F2011 was prepared in accordance with Canadian GAAP.*

OPERATING STATISTICS

for the years ended or as at March 31	2014	2013	2012	2011	2010
Generating Capacity (megawatts)					
Hydroelectric[1]	**10,927**	10,927	10,923	10,923	10,259
Thermal	**1,120**	1,120	1,117	1,096	1,086
Total	**12,047**	12,047	12,040	12,019	11,345
Peak One-Hour Demand					
Integrated System (megawatts)	**10,072**	9,345	9,929	9,790	9,847
Customers					
Residential	**1,709,071**	1,689,050	1,671,412	1,654,079	1,633,558
Light industrial and commercial	**201,812**	199,981	197,821	195,402	193,522
Large industrial	**177**	172	168	166	163
Other	**3,489**	3,482	3,490	3,490	3,455
Trade	**239**	249	264	269	287
Total	**1,914,788**	1,892,934	1,873,155	1,853,406	1,830,985
Average number of customers per full time equivalent[2]	**330**	330	317	317	311
Electricity Sold (gigawatt-hours)					
Residential	**17,965**	17,703	18,395	17,797	17,593
Light industrial and commercial	**18,501**	18,384	18,005	18,052	17,811
Large industrial	**13,994**	13,508	13,522	13,164	13,020
Other	**2,558**	7,417	2,275	1,647	1,809
Domestic	**53,018**	57,012	52,197	50,660	50,233
Trade	**50,082**	59,957	54,548	49,615	48,842
Total	**103,100**	116,969	106,745	100,275	99,075
Total electricity sold per full time equivalent (gigawatt-hours)[2,3]	**13.33**	15.43	13.46	13.25	13.43
Revenues (in millions)[4]					
Residential	**$ 1,648**	$ 1,622	$ 1,531	$ 1,366	$ 1,272
Light industrial and commercial	**1,378**	1,382	1,321	1,243	1,192
Large industrial	**785**	731	680	590	590
Other energy sales	**508**	303	216	239	235
Domestic	**4,319**	4,038	3,748	3,438	3,289
Trade	**1,073**	860	982	578	739
Total	**$ 5,392**	$ 4,898	$ 4,730	$ 4,016	$ 4,028

1 *Maximum sustained generating capacity.*
2 *Regular full time equivalents (FTEs) (actual regular hours worked during the year divided by expected regular working hours during the year) for BC Hydro, excluding subsidiaries.*
3 *The method used to calculate the total electricity sold per full time equivalent (gigawatt-hours) excludes trade gas gross gigawatt-hours.*
4 *Revenues and average revenues are net of regulatory transfers.*

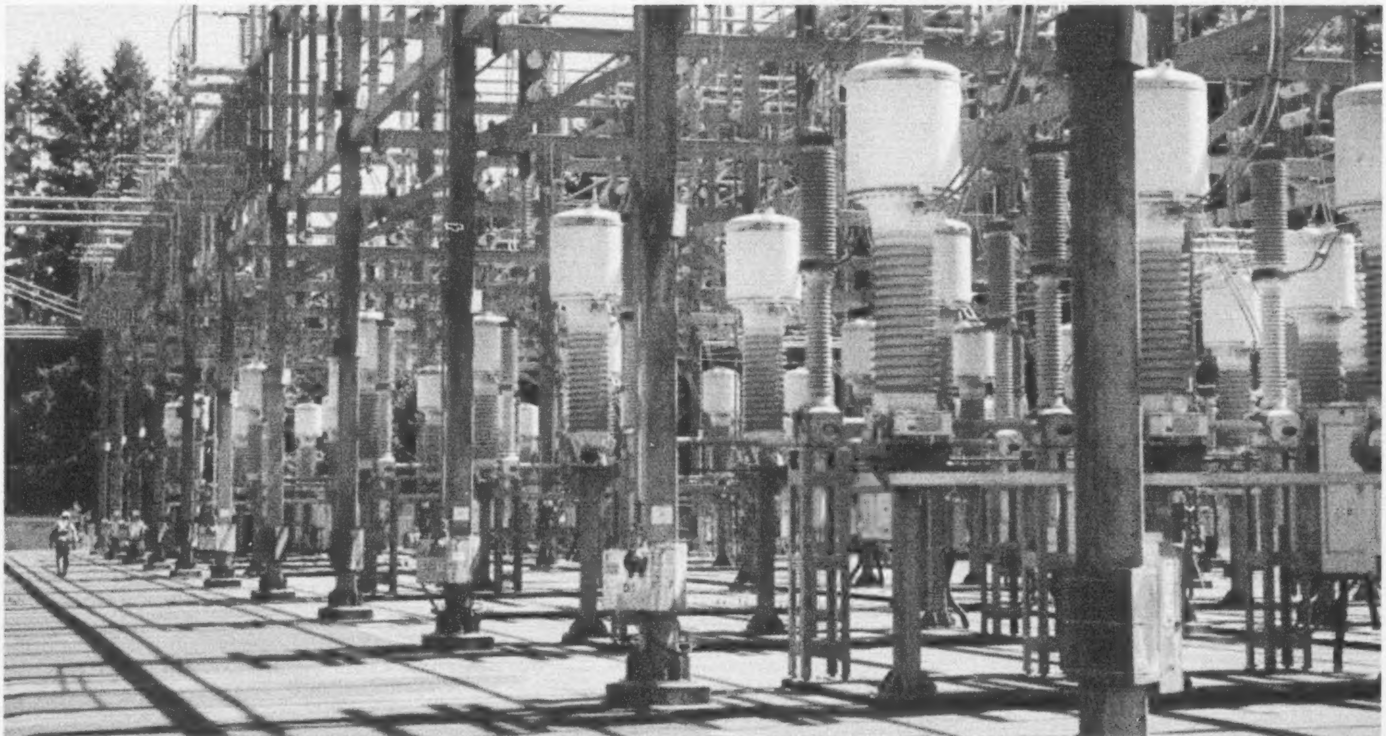
OPERATING STATISTICS
(CONTINUED)

for the years ended or as at March 31	2014	2013	2012	2011	2010
Average Revenue (per kilowatt-hour)[1]					
Residential	**9.2¢**	9.2¢	8.3¢	7.7¢	7.2¢
Light industrial and commercial	**7.4**	7.5	7.3	6.9	6.7
Large industrial	**5.6**	5.4	5.0	4.5	4.5
Other	**19.9**	4.1	9.5	14.5	13.0
Trade	**4.6**	3.1	4.0	4.0	4.4
Average Annual Kilowatt-Hour Use Per Residential Customer	**10,571**	10,534	11,067	10,818	10,857
Lines In Service					
Distribution (kilometres)	**58,317**	58,115	57,914	57,648	57,278
Transmission (circuit kilometres)	**19,322**	19,163	18,864	18,764	18,603

[1] *Revenues and average revenues are net of regulatory transfers.*

TOTAL REQUIREMENTS FOR ELECTRICITY, SOURCES OF SUPPLY AND WATER INFLOWS

for the years ended March 31	2014			2013			2012			2011			2010		
	Generating Capacity (Megawatts)	Gigawatt-Hours	%	Generating Capacity (Megawatts)	Gigawatt-Hours	%	Generating Capacity (Megawatts)	Gigawatt-Hours	%	Generating Capacity (Megawatts)	Gigawatt-Hours	%	Generating Capacity (Megawatts)	Gigawatt-Hours	%
Requirements															
Domestic	12,047	53,018	65.0	12,047	50,992	58.5	12,040	52,197	62.2	12,019	50,660	62.1	11,345	50,233	60.3
Electricity trade		23,806	29.2		30,975	35.6		26,908	32.1		26,253	32.2		28,210	33.9
		76,824	94.2		81,967	94.1		79,105	94.3		76,913	94.3		78,443	94.2
Line loss and system use		4,733	5.8		5,159	5.9		4,783	5.7		4,648	5.7		4,840	5.8
		81,557	100.0		87,126	100.0		83,888	100.0		81,561	100.0		83,283	100.0
Sources Of Supply															
Hydroelectric generation															
Gordon M. Shrum	2,730	13,650	16.7	2,730	15,878	18.2	2,730	14,447	17.2	2,730	10,015	12.3	2,730	14,756	17.7
Revelstoke	2,480	8,121	10.0	2,480	9,760	11.2	2,480	8,756	10.4	2,480	7,155	8.8	1,980	7,061	8.5
Mica	1,805	7,030	8.6	1,805	7,873	9.0	1,805	7,943	9.5	1,805	6,294	7.7	1,805	6,549	7.9
Kootenay Canal	583	2,935	3.6	583	3,595	4.1	583	3,108	3.7	583	2,924	3.6	583	2,255	2.7
Peace Canyon	694	3,423	4.2	694	3,902	4.5	694	3,613	4.3	694	2,591	3.2	694	3,709	4.4
Seven Mile	805	3,183	3.9	805	3,176	3.6	805	3,491	4.2	805	3,210	3.9	805	2,870	3.4
Bridge River	478	2,397	2.9	478	2,626	3.0	478	2,732	3.3	478	2,631	3.2	478	1,948	2.3
Other	1,352	4,589	5.6	1,352	5,304	6.1	1,348	5,743	6.9	1,348	4,483	5.5	1,184	4,059	4.9
	10,927	45,328	55.5	10,927	52,115	59.8	10,923	49,833	59.5	10,923	39,303	48.2	10,259	43,207	51.8
Thermal generation															
Burrard	950	84	0.1	950	25	0.0	950	19	0.0	950	58	0.1	950	233	0.3
Other	170	184	0.2	170	97	0.1	167	124	0.1	146	193	0.2	136	315	0.4
Purchases under long-term commitments		15,300	18.8		15,003	17.2		15,317	18.3		15,427	18.9		13,403	16.1
Purchases under short-term commitments		20,764	25.5		19,858	22.8		18,640	22.2		26,208	32.1		27,217	32.7
Other		(103)	(0.1)		28	0.0		(45)	(0.1)		372	0.4		(1,092)	(1.3)
	12,047	81,557	100.0	12,047	87,126	100.0	12,040	83,888	100.0	12,019	81,561	100.0	11,345	83,283	100.0
Water Inflows (% of average)			95			109			108			86			87



HOW TO CONTACT BC HYDRO:

Lower Mainland
604 BCHYDRO (604 224 9376)

Outside Lower Mainland
1 800 BCHYDRO (1 800 224 9376)

HEAD OFFICE

333 Dunsmuir Street
Vancouver, B.C. V6B 5R3
bchydro.com

BC Hydro's Service Plan can be found online at **http://www.bchydro.com/about/accountability_reports/financial_reports/service_plan.html**

The Annual Report **http://www.bchydro.com/about/accountability_reports/financial_reports/annual_reports.html** summarizes what BC Hydro has done to address the strategies and objectives laid out in BC Hydro's 2013/14 to 2015/16 Revised Service Plan.

BC hydro
FOR GENERATIONS

BRITISH COLUMBIA

GDS14-090